CANADIAN ENERGY

Supply and Demand

1980 - 2000

15

National Energy Board

June 1981

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"The Board may of its own motion inquire into, hear and determine any matter or thing that under this Act it may inquire into, hear and determine."

National Energy Board Act
Part 1, Subsection 14(2)

"In the Matter of an inquiry into the supply of oil, natural gas, and other forms of energy in relation to the domestic demand for all forms of energy, and the supply/demand balances for hydrocarbons and electricity;"

National Energy Board Hearing
Order EHR-1-80, dated
17 April 1980.

PREFACE

In light of the rapid changes characterizing the Canadian energy scene, the National Energy Board held a public inquiry on the supply of oil, natural gas and other forms of energy in relation to the domestic demand for all forms of energy and the supply/demand balances for hydrocarbons and electricity. This inquiry started in November 1980 and concluded in February 1981.

The National Energy Board gratefully acknowledges the contributions of Submittors. In addition to material presented to the inquiry, many Submittors applied their specialized knowledge to respond to specific requests for information from the Board enabling a more complete national energy picture to be compiled.

This report is issued under the authority of the National Energy Board Act. The Board believes that the national interest is well served by the public hearing process and hopes that the information contained in this report will assist the many parties concerned with Canada's energy future.

5 June 1981

L.M. Thur
Presiding Member

J.R. Jenkins
Member

R.B. Horner
Member

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RECITAL AND ORDER OF APPEARANCE

A public inquiry in the matter of the supply of oil, natural gas and other forms of energy in relation to the domestic demand for all forms of energy, and the supply/demand balances for hydrocarbons and electricity, held pursuant to Part II of the National Energy Board Act.

File: 1045-3

HEARD at

Vancouver, British Columbia on 19 and 20 November 1980
Calgary, Alberta on 24, 25 and 26 November 1980
Halifax, Nova Scotia on 10 December 1980
Québec City on 12 December 1980
St. John's, Newfoundland on 6 January 1981
Ottawa, Ontario on 12, 13, 14, 15, 16, 19, 20, 21, 22, 26, 27, 28, 29, 30 January and 2, 3, 4, 5, and 6 February 1981

BEFORE:

L.M. Thur	Associate Vice-Chairman
J.R. Jenkins	Member
R.B. Horner	Member

APPEARANCES:

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	A. Sears	Dow Chemical of Canada, Limited
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	J.D. Brett	ICG Brunswick Gas Ltd.
	J. Carstairs	ICG Canadian Propane Limited
	W.J. Hartnett	Imperial Oil Limited
	C.K. Yates	Independent Petroleum Association of Canada

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C.L. Campbell	Union Carbide Canada Limited
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ABBREVIATION OF NAMES

"AERCB"	Alberta Energy Resources Conservation Board
"API"	American Petroleum Institute
"A & S"	Alberta and Southern Gas Co. Ltd.
"Algonquin"	Algonquin Gas Transmission Company
"Amoco"	Amoco Canada Petroleum Company Ltd.
"AMPC"	Association of Major Power Consumers in Ontario
"ANG"	Alberta Natural Gas Company Ltd.
"B.C."	The Minister of Energy, Mines, and Petroleum Resources, Province of British Columbia
"(the) Board"	(the) National Energy Board
"Canadian Hunter"	Canadian Hunter Exploration Ltd.
"Canadian Propane"	ICG Canadian Propane Ltd.
"CAODC"	The Canadian Association of Oilwell Drilling Contractors
"CARC"	Canadian Arctic Resources Committee
"CDC"	CDC Oil & Gas Limited
"CERI"	Canadian Energy Research Institute
"CFA"	The Canadian Federation of Agriculture
"Chevron Canada"	Chevron Canada Limited
"Chevron Standard"	Chevron Standard Limited
"CIPREC"	Canadian Institute of Public Real Estate Companies
"CNG"	Consolidated Natural Gas Limited
"Coal Assn."	The Coal Association of Canada
"COFI"	The Council of Forest Industries
"Columbia"	Columbia Gas Development of Canada Ltd.
"Comaplex"	Comaplex Resources International Ltd.
"Cominco"	Cominco Ltd.
"Consolidated"	Consolidated Natural Gas Limited
"Consumers"	The Consumers' Gas Company, A Division of Hiram-Walker Consumers Home Ltd.

"CPA"	Canadian Petroleum Association
"DEVCO"	Cape Breton Development Corporation
"Dome"	Dome Petroleum Limited
"Dow"	Dow Chemical of Canada Limited
"EMR"	Energy, Mines and Resources
"Fisher's"	F.T. Fisher's Sons Ltd.
"Genstar"	Genstar Chemical Limited
"GIC"	Gaz Inter-Cité Québec Inc.
"GMi"	Gaz Métropolitain inc.
"GWG"	Greater Winnipeg Gas Company
"Gulf"	Gulf Canada Limited Gulf Canada Resources, Inc.
"HBOG"	Hudson's Bay Oil and Gas
"Home"	Home Oil Company Limited
"Husky"	Husky Oil Operations Ltd.
"ICF"	Institute for Canadian Futures
"ICG"	Inter-City Gas Corporation
"ICG (NB)"	ICG New Brunswick Gas Ltd.
"ICG (PW)"	ICG Utilities (Plains-Western) Ltd.
"ICG Scotia"	ICG Scotia Gas Limited
"IES"	Institute for Environmental Studies, University of Toronto
"IGUA"	Industrial Gas Users Association
"Imperial"	Imperial Oil Limited
"Inland"	Inland Natural Gas Co. Ltd.
"IPAC"	Independent Petroleum Association of Canada
"IPL"	Interprovincial Pipe Line Limited
"Lone Rock"	Lone Rock Energy Limited
"Manitoba"	The Attorney-General, Province of Manitoba
"Midwestern"	Midwestern Gas Transmission Company
"Mobil"	Mobil Oil Canada, Ltd.

"Montreal Pipe Line"	Montreal Pipe Line Limited
"Murphy"	Murphy Oil Company Ltd.
"NBEPC"	The New Brunswick Electric Power Commission
"NC Gas"	Northern and Central Gas Corporation Limited
"NEB"	National Energy Board
"New Brunswick"	Energy Secretariat, Government of New Brunswick
"Newfoundland"	Department of Mines and Energy Government of Newfoundland and Labrador
"Nfld Light"	Newfoundland Light & Power Co. Limited
"Norcen"	Norcen Energy Resources Limited
"Northwest Alaska"	Northwest Alaskan Pipeline Company
"Northwest Pipeline"	Northwest Pipeline Corporation
"NOVA"	NOVA, An Alberta Corporation
"Nova Scotia"	Department of Mines and Energy Province of Nova Scotia
"NRC"	National Research Council
"NWT"	Department of Justice and Public Services The Government of the Northwest Territories
"Ontario"	Ministry of Energy, Province of Ontario
"Pacific Interstate"	Pacific Interstate Transmission Company
"Pan-Alberta"	Pan-Alberta Gas Ltd.
"Panarctic"	Panarctic Oils Ltd.
"Petrofina"	Petrofina Canada Inc.
"Pétromont"	Pétromont Inc.
"Petrosar"	Petrosar Limited
"PGAC"	Propane Gas Association of Canada Inc.
"Polar"	Polar Gas Limited
"ProGas"	ProGas Limited
"Québec"	Procureur Général du Québec Gouvernement du Québec
"Saskatchewan"	Department of Mineral Resources Province of Saskatchewan
"Shell"	Shell Canada Limited, Shell Canada Resources Limited

"SPC"	Saskatchewan Power Corporation
"Suncor"	Suncor Inc.
"Sundance"	Sundance Oil Canada Ltd.
"TCPL"	TransCanada PipeLines Limited
"Tennessee Gas Pipeline"	Tennessee Gas Pipeline Company (Division of Tenneco Inc.)
"Texaco"	Texaco Canada Inc.
"TQM"	Trans Québec & Maritimes Pipeline Inc.
"Transco"	Transcontinental Gas Pipe Line Corporation
"Union"	Union Gas Limited
"Union Carbide"	Union Carbide Canada Limited
"Vancouver Island Gas"	Vancouver Island Gas Company Ltd.
"WTCL"	Westcoast Transmission Company Limited

ABBREVIATION OF TERMS

ACQ	Annual Contract Quantity
AGE	Alberta Gas Ethylene Plant
API	American Petroleum Institute
APP	Arctic Pilot Project
BER	Beyond economic reach
CF	Capacity Factor
CHIP	Canadian Home Insulation Program
CNG	Compressed Natural Gas
CPI	Consumer price index
COR	Canadian Ownership Requirement
EJ	Exajoule (10^{18} J)
EOR	Enhanced oil recovery
FIRA	Foreign Investment Review Act
FOB	Free on Board
GJ	Gigajoule (10^{9} J or 0.95 MMBtu)

GNE Gross National Expenditure

GNP Gross National Product

GPP Gross Provincial Product

GW Gigawatt (10^9 watts)

GW.h Gigawatt hour (10^9 watt hours)

J Joule

kW Kilowatt (10^3 watts)

kW.h Kilowatt hour (10^3 watt hours)

LF Load Factor

LNG Liquefied Natural Gas

LNG Liquefied Natural Gas

LPG Liquefied Petroleum Gases

m³ Cubic metre (approximately 6.3 barrels or 35.3 cubic feet)

m³/d Cubic metre(s) per day

MJ Megajoule (10^6 J)

Mm Megametre (10^6 metres)

MW Megawatts

MW.h Megawatt hour (10^6 watt hours)

NEP National Energy Program

NGL Natural Gas Liquids

PGRT Petroleum and Natural Gas Revenue Tax

PJ Petajoule (10^{15} J)

PIP Petroleum Incentives Program

RDP Real Domestic Product

SNG Synthetic Natural Gas

TJ Terajoule (10^{12} J)

TW.h Terawatt hour (10^{12} watt hours)

REFERENCE REPORTS

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"1975 Gas Report"	Canadian Natural Gas Supply and Requirements – National Energy Board – April 1975
"1975 Oil Report"	Canadian Oil Supply and Requirements – National Energy Board – September 1975
"1977 Oil Report"	Canadian Oil Supply and Requirements - National Energy Board – February 1977
"1978 Oil Report"	Canadian Oil Supply and Requirements - National Energy Board – September 1978
"1979 Gas Report"	Canadian Natural Gas Supply and Requirements - National Energy Board – February 1979
"November 1979 Reasons for Decision"	National Energy Board – Reasons for Decision In the Matter of Applications under Part VI of the National Energy Board Act of Alberta and Southern Gas Co. Ltd., Canadian-Montana Pipe Line Company, Columbia Gas Development of Canada Ltd., Consolidated Natural Gas Ltd., Niagara Gas Transmission Limited, Pan-Alberta Gas Ltd., ProGas Limited, Sulpetro Limited, TransCanada PipeLines Limited, Westcoast Transmission Company Limited, – November 1979
"April 1980 Reasons for Decision"	National Energy Board – Reasons for Decision In the Matter of the Applications under Part III of the National Energy Board Act of TransCanada PipeLines Limited, Q & M Pipe Lines Ltd. – April 1980
"AERCB Report 80-18"	Alberta's Reserves of Crude Oil, Gas Natural Gas Liquids and Sulphur at 31 December 1979
"Saskatchewan Annual Reserves Publication"	Reservoir Annual 1979, Saskatchewan Mineral Resources, Petroleum and Natural Gas – Miscellaneous Report 80-1

DEFINITIONS

°API – Degree(s) API — A relative measure of the specific gravity of crude oils. Crude oils with a higher value of °API have a lower specific gravity.

Associated Gas — Natural gas, commonly known as gas cap gas, which overlies and is in contact with crude oil in the reservoir, except where the volume of oil is small and where production of such gas does not significantly affect the crude oil recovery.

Base Load Capacity — Electricity generating equipment which operates to meet the demand that continues throughout most of the year.

Beyond Economic Reach Reserves — Those established reserves which because of size, geographic location or composition are not considered economically connectable to a pipeline at the present time.

Bitumen — A naturally occurring viscous mixture composed mainly of hydrocarbons heavier than pentane which may contain sulphur compounds and that in its natural state is not recoverable at a commercial rate through a well.

Blowdown — The production of gas either from the gas cap of an oil reservoir normally after depletion of the oil, or from a cycled gas pool upon cessation of the cycling operation.

CANDIDE — A large computerized econometric model of the Canadian economy which has been developed by the Economic Council of Canada with the assistance of several departments of the Federal Government. The development of the model has been proceeding since 1970, and a recent version, T.I.M., was developed in 1979 by Informetrica Limited as an enhanced variant of versions 1.0, 1.1, and 1.2 of CANDIDE. The version of T.I.M. being used at the Board is available exclusively for Board's purposes and includes further modifications made by Board staff.

Capability — Maximum electric energy which the system can supply under specified conditions in a given time interval. Energy capability is the product of capacity multiplied by time, and is expressed in kilowatt hours, or some multiple thereof.

Capacity — The electric power that a piece of equipment can generate, utilize or transfer, and is expressed in kilowatts or some multiple thereof.

Capture Rate — The proportion of new customers selecting a particular fuel to meet their energy requirements.

Carbon Dioxide (CO) Flooding — A tertiary recovery process in which carbon dioxide is injected into the reservoir under conditions which result in the injected material mixing with the reservoir fluid.

Chemical Flooding — A tertiary recovery process in which water with added chemicals is injected into a petroleum reservoir. Three of the common groups of chemicals which may be added are surfactants, polymers, and alkaline chemicals.

City-Gate Price	The average price charged by a natural gas transmission company for gas delivered at a 100 per cent load factor at the point of delivery, or sale, to a gas distribution company.
Co-generation	Energy conversion system which produces both elecricity and process steam or steam for heating with a resultant overall improvement in conversion efficiency.
Condensate	As used herein, synonymous with pentanes plus.
Conventional Areas	Those areas of Canada which have a long history of hydrocarbon production. Conventional areas are also referred to as non-frontier areas.
Conversion Rate	Percentage of existing customers switching from one fuel to another over a given period of time.
Crude Oil and Equivalent Hydrocarbons	Sometimes referred to as 'Crude Oil and Equivalent'. Includes crude oil, synthetic crude oil produced from oil sands plants, and pentanes plus.
Cycling Gas Pool	A natural gas pool into which part or all of the produced natural gas is reinjected after removal of natural gas liquids in a gas processing plant.
Deferred Reserves	Those quantities of established reserves which for a specific reason, usually because of involvement in a recycling or pressure maintenance project, are not now available for market.
Deliverability	A general term used to refer to an actual or expected rate of natural gas production.
Eastern Zone	For rate design purposes, the Eastern Zone encompasses the geographic area from North Bay to Montreal including Toronto and Southern Ontario. The NEP assumes that the Eastern Zone will be extended to include the Maritimes. Within the Eastern Zone all distributors pay the same rate for a given service.
Established Reserves	Those reserves recoverable under current technology and present and anticipated economic conditons, specifically proved by drilling, testing or production, plus that judgement portion of contiguous recoverable reserves that is interpreted to exist, from geological, geophysical or similar information, with reasonable certainty.
–Initial Established Reserves	Established reserves prior to the deduction of any production.
–Remaining Established Reserves	Initial established reserves less cumulative production.
Export of electricity	Transfer of power or energy from one utility system to another. Export from a Canadian system to one in the United States requires an NEB licence.

Feedstock — Raw material supplied to a refinery or petrochemical plant.

Flat Life — That period of the producing life of a resource during which production is maintained at a constant rate before decline commences.

Frontier Areas — Those areas of Canada which have a potential for but no history of production. These include the Mackenzie Delta-Beaufort Sea area, the Arctic Islands and the offshore areas.

Fuel Efficiency — When a fuel is burned, the amount of useful output energy, expressed as a percentage of the theoretical input energy content of the fuel. Fuel efficiency for a heating fuel is less than 100 per cent to the extent that heated air is used in combustion and to the extent that exhaust venting is necessary. In other applications fuel efficiencies are less than 100 percent partly because of waste heat generation.

Heating Degree-Days — A unit measuring the extent to which the outdoor mean daily dry-bulb temperature (average of maximum and minimum) falls below 18° Celsius. One degree-day is counted for each degree of deficiency below the assumed base temperature of 18° Celsius for each calender day on which such deficiency occurs. (On the Fahrenheit scale, the assumed reference temperature is 65°F.).

Heavy Crude Oil — A term loosely applied to crude oils with a low API gravily. Appendix J lists the crude streams which are included in the National Energy Board's definition of the heavy crude category.

Heavy Fuel Oil — In this report the term heavy fuel oil is used to include bunker fuel oils which are No. 5 and No. 6 fuel oils and also industrial fuel oil which is No. 4 fuel oil.

Hog Fuel — Fuel consisting of bark, shavings, sawdust and low grade lumber and lumber rejects from the operation of pulp mills, sawmills and plywood mills.

Hydroelectric Generation — Conversion of the energy of falling water to electric energy.

Infill Drilling — The process of drilling additional wells within the defined limits of a producing field.

In Situ Recovery — With reference to oil sands deposits, the use of techniques to recover bitumen without the necessity of mining the sands.

International Price of Crude Oil — A generalization for the 'going price' of crude oil in the world markets.

Light Crude Oil — A term applied to crude oils with a high API gravity. Generally, the light crude oil category includes all crude oil and equivalent hydrocarbons not included in the definition of heavy crude oil.

Liquefied Petroleum Gases (LPG) — As used in this report, the term refers to the hydrocarbons propane and butanes, or combinations thereof.

Marketable Natural Gas	Natural gas which is available to a transmission line after removal of certain hydrocarbons and non-hydrocarbon compounds present in the raw natural gas and which meets specifications for use as a domestic, commercial, or industrial fuel. Marketable natural gas excludes field and plant fuel and losses, excepting those related to downstream reprocessing plants.
Middle Distillates	The range of refined petroleum products which includes kerosene, stove oil, diesel fuel, and light fuel oil.
Millidarcy	See 'Permeability'
Miscible Flooding	An enhanced recovery process in which fluid, capable of dissolving in the oil it contacts, is injected into a reservoir to form a single liquid that can move through the reservoir to a producing well more easily than the original crude oil.
Natural Gas Liquids	Natural gas liquids are those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants or recovered from field separators, scrubbers, or other gathering facilities. These liquids include the hydrocarbon components ethane, propane, butanes, and pentanes plus or a combination thereof.
Netback	The revenue available to the producer to pay the supply cost, that is, total revenue less payments to governments.
Non-Associated Gas	Natural gas not in contact with crude oil in the reservoir or natural gas in contact with crude oil where the volume of oil is small and where production of such gas does not significantly affect the crude oil recovery.
Oil Sands	Deposits of sand and other rock aggregate which contain bitumen. As used in this report, includes Athabasca, Buffalo Head Hills, Cold Lake, Peace River, and Wabasca deposits. See also 'Bitumen'.
Peaking Capacity	Electricity generating equipment which is operated to supply peaks in demand of the power system (usually low capital and high operating cost).
Pentanes Plus	A volatile hydrocarbon liquid composed primarily of pentanes and heavier hydrocarbons. Generally, a by-product obtained from the production and processing of natural gas.
Permeability	Permeability is a property of a porous medium and is a measure of the capacity of the medium to transmit fluids. (common unit of measurement is the millidarcy)
Power and/or Energy —Firm	Means electric power and/or energy intended to be available at all times in accordance with an agreement.
—Interruptible	Means electric power and/or energy that may be interrupted at the supplier's discretion.

Productive Capacity:	The estimated average daily ability to produce that could be achieved, unrestricted by demand, but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing and pipeline capacity.
Pulping Liquor (also known as waste liquor or black liquor)	A substance primarily made up of lignin, a substance found in wood, and is a by-product of the manufacture of chemical pulp. It can be burned in a boiler to produce steam or electricity.
Rate of Take	The average daily rate of production of natural gas related to the volume of initial established reserves assigned to the reservoir or reservoirs from which that production is obtained. For example 1:7300 means one standard cubic metre per day of production for each block of 7 300 cubic metres of initial established reserves.
Raw Natural Gas	The lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which, under atmospheric conditions, is essentially a gas, but which may contain liquids.
Recovery —Primary Recovery	The volume of crude oil and natural gas recoverable by natural depletion processes only.
—Secondary Recovery	The incremental volume of crude oil and natural gas recoverable by conventional waterflooding, pressure maintenance or cycling.
—Tertiary Recovery	The incremental volume of crude oil and natural gas recoverable by a process after or in lieu of conventional waterflooding, pressure maintenance or cycling. A tertiary recovery process may be implemented without a preceding secondary recovery scheme.
—Enhanced Recovery	A general term for the incremental volume of crude oil and natural gas recoverable over the volume recoverable by natural depletion processes only. Enhanced recovery is the sum of secondary and tertiary recovery.
Refinery-Gate Price	The delivered price of crude oil to a refinery, including all transportation charges to that point.
Remaining Established Reserves	See 'Established Reserves'
Reserves Additions	Incremental changes to established reserves resulting from the discovery of new pools and reserves appreciation.

Reserves Apprecia-tion	Incremental change in established reserves resulting from extensions to existing pools and/or revisions to previous reserves estimate and/or by the application of improved recovery methods.
Reserve (electricity)	The capacity margin between peak load and rated capacity. 'Planned' reserve is the provision for scheduled outages, unanticipated demand, and the provision for probability of unplanned outages – usually 10-25 per cent of peak load. 'Surplus' in this report refers to capacity in excess of the peak load plus planned reserve.
Shut-in Capacity	The unused production capability of currently producing oil and gas wells plus the total production capability of all shut-in oil and gas wells whether or not they are connected to surface gathering and producing facilities.
Solar Active	System uses solar radiation as the energy source and transfers heat by using pumps, fans, or other mechanical devices.
Solar Passive	System collects solar radiation directly for space heating, water heating or other similar purposes without using mechanical devices.
Solution Gas	Natural gas which is in solution with crude oil in the reservoir at original reservoir conditions and which is normally produced with the crude oil.
Solvent Flooding	See 'Miscible Flooding'
Straddle Plant	A natural gas processing plant in which gas is further processed, subsequent to field processing, to remove additional NGL. Generally, the plant is located on a main transmission system and is said to 'straddle' the pipeline; also known as a reprocessing plant.
Supply Capability	The deliverability that could be achieved from a gas reservoir or group of reservoirs when restricted only by reservoir performance, well density and well capacity, field processing capacity, and contract rates.
Supply Cost	The sum of capital costs and operating costs per unit of production, allowing for a return on producer's investment.
Supply Tracking	A supply forecasting procedure utilized during a period when supply capability exceeds demand, whereby deliverability is restricted to (or 'tracks') that demand until such time as supply capability falls below the demand level.
Synthetic Crude Oil	Crude oil produced through treatment of bitumen in upgrading facilities designed to decrease its viscosity and sulphur content. See also 'Bitumen'.
Synthetic Natural Gas	Synthetic or substitute natural gas made synthetically from petroleum liquids or coal.
Thermal Generation	Energy conversion in which fuel is consumed to generate heat energy which is then converted to electric energy. Conventionally, the fuel may be coal (coal-fired), oil (oil-fired), gas (gas-fired), or uranium (nuclear).

Thermal Processes — Tertiary recovery processes in which heat is added to the reservoir. Two principal thermal processes are steam flooding and in situ combustion. In steam flooding, steam is injected into the reservoir. In situ combustion involves ignition of oil in the reservoir and burning a portion of the oil in place to generate heat.

Toronto Reference Price (Toronto City Gate) — The price of Alberta gas delivered at Toronto, determined as an energy equivalent value of the price of crude oil at Toronto, in accordance with Federal-Alberta gas-pricing agreements.

Transmission — The movement or transfer of electricity from one point to another in a power system.

Ultimate Potential — An estimate of the initial established reserves which will have become developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of the area and anticipated technology and economic conditions. Ultimate potential includes cumulative production, remaining established reserves and future additions through extensions and revisions to existing pools and the discovery of new pools.

Waterflooding — The process of injecting water into a reservoir for the purpose of displacing oil towards a production well.

Wellhead — Specifically, the equipment placed on top of a well at the surface to maintain control of the well. More generally, it is used to specify a delivery point in the production system (e.g., the wellhead price).

World Price — See 'International Price of Crude Oil'.

PART I

INTRODUCTION

SUMMARY & CONCLUSIONS

ISSUES

CHAPTER 1
INTRODUCTION

1.1 Background

In the late 1960s the National Energy Board undertook a study of energy supply and demand in Canada. The report, issued in 1969,[1] covered all forms of energy in Canada and the probable sources of supply for serving both indigenous and export demand for Canadian energy. The primary reason for this undertaking was to identify developing energy trends in Canada.

Since then the Board has undertaken periodic examinations of the supply and demand for Canadian hydrocarbons. Each of these reviews, however, has dealt separately with either natural gas or crude oil and equivalent.

In 1972 the Board conducted an internal review of the potential limitations of Canadian petroleum to continue to supply both the domestic and the export markets as these were expected to develop in the future. On the recommendation of the Board the government introduced export controls on crude oil early in 1973 and stated that the problem was of sufficient magnitude to warrant a public hearing by the Board. The Board held a public hearing and released its report in October 1974 in which it published a single forecast for oil. The Board adopted a protection procedure designed to limit exports when ten years of future Canadian requirements for indigenous crude oil and equivalent feedstocks could not be assured from Canadian resources.

A second oil report, published in September 1975, recommended a further reduction in the allowable export volumes in view of the growing possibility of supply difficulties facing Canadian oil users.

A third oil report published in February 1977 used a different approach in that forecasts of requirements for indigenous feedstocks were dealt with within a total primary energy demand framework. In addition, requirements for light and heavy crude oil were treated separately. Consideration of various scenarios led the Board to envisage that indigenous crude supply during the 1980s might prove insufficient to meet the needs of refineries west of the Ottawa Valley.

A fourth report was initiated at the request of the government to examine whether additional oil importing capability would be required. This report, published in September 1978, concluded that no additional facilities would be required through 1995 because of an anticipated lower growth in demand as well as an improved supply forecast, particularly in oil sands development.

In 1974-75 the Board conducted the first of its public hearings on Canadian natural gas supply and requirements not directly associated with an export application. As with the first two oil reports, the forecast demand for natural gas was not integrated with estimates of the total demand for primary energy, although several demand scenarios were developed to underscore the high degree of uncertainty, especially in regard to prices and conservation programs which were being initiated as a result of the 1973 oil embargo. The evidence indicated that Canadian demand for natural gas plus existing export commitments was expected to exceed the supply available from conventional areas and that other major new sources of natural gas supply would be necessary by the mid 1980s. The Board concluded that more weight should be given to deliverability as distinct from reserves and that higher field prices would induce greater supply. A new approach to licensing of natural gas exports placing more emphasis on deliverability would be required to ensure that Canadian requirements were being met on a continuing basis. In addition, the complexities and uncertainties related to frontier gas would require the Board to maintain some flexibility when considering applications for export licences.

A second inquiry was held in 1978-1979. The purpose was not only to examine Canadian natural gas supply/demand in the view of possible applications for licences to export natural gas but also to review the Board's procedures for calculating surplus. As a result of this hearing, the Board concluded that the determination of natural gas surplus should be made using three tests: namely, a Current Deliverability Test, a Current Reserves Test, and a Future Deliverability Test. All three tests would have to be met before the Board would declare a surplus to exist.

1.2 1980 All Energy Inquiry

In early 1980 the Board concluded that changing circumstances warranted a comprehensive appraisal of the energy outlook. Such an appraisal would deal in detail with all energy forms to the end of the century using a common set of assumptions. It would cover the supply of oil, natural gas and other forms of energy in relation to the domestic demand for all forms of energy and the supply/demand balances for hydrocarbons and electricity. The intent was to determine the extent to which total Canadian energy demand could be met by indigenous supplies over the period to the year 2000 after providing for authorized exports. It was not the purpose of this inquiry to dispose of any specific application which was before the Board or which might come before the Board in the near future.

By its Hearing Order EHR-1-80 dated 17 April 1980 shown in Appendix A, the Board announced that a public inquiry would be held in the last quarter of 1980 in major Canadian cities. After the hearing order had been released, and prior to the commencement of the hearing, the Federal government announced its National Energy Program (NEP). The Board then decided to offer the opportunity to Submittors to provide supplemental submissions on the probable impact the program might have on their forecasts.

In response to the Board's order, 96 submissions were received. Eight provinces were represented as were the petroleum indus-

[1] Board reports are listed under Reference Reports.

try, electric power utilities, coal and petroleum industry associations and several segments of Canadian society. Some Submittors amended the material previously filed while others responded only in a qualitative manner on the expected impacts of the NEP on their forecasts. Viva voce evidence was also presented to the Board by many Submittors.

1.3 Uncertainties in Forecasting

For a number of years the Board has adopted the approach in forecasting energy supply and demand to provide several forecast cases, often providing three cases for supply and demand. In this way, in effect, the Board has used a range of forecasts. In addition, each of the Board's reports represents an update of its forecasts contained in previous reports. It is by these procedures that the Board has attempted to resolve the problem of uncertainty in its forecasting.

To develop alternative forecasts, the Board varies the underlying assumptions related to the main parameters of supply and demand. For supply they are: estimates of rates of discovery and ultimate potential, netbacks available to industry, operating and capital costs, and technological progress. For energy demand, the Board varies assumptions related to demography, the level of economic activity and energy prices.

At the present time, the need to use forecast ranges rather than single point forecasts is even more compelling than previously.

The NEP, which may be characterized as a structural policy, has introduced new and important policy thrusts which will require an adaptation on behalf of industry. The NEP states that the centerpiece of the program is a drive to reduce oil consumption. In addition, it sets objectives to increase Canadian ownership and control to at least 50 percent of the industry. Also, the program intends to encourage industry to explore and develop on Canada Lands, i.e., in the frontier. Furthermore, significant measures are proposed to provide a more equitable sharing of petroleum revenues between the provincial and federal governments and industry.

The means, modalities and administrative arrangements to fulfill these objectives, and more particularly the pricing and taxation elements, will take time to settle and consequently the forecasting horizon is now more clouded than usual.

As a consequence, in the present circumstances, the Board has developed more cases for supply and demand than previously.

For oil supply, the Board has forecast a base case, a modified base case, a high case and a low case. The base case illustrates the assumption that the measures proposed in the NEP would be applied without compromise. The modified base case assumes that an agreement is realized by the federal and provincial governments on pricing and taxation in such a way that netbacks to industry are adequate to assure a higher oil supply than in the base case. The high and low cases are the Board's estimates of the upper and lower limits to its forecasts.

A number of Submittors expressed concern about lack of agreement and its effect on Canada's oil supply and the possible adverse macroeconomic consequences, particularly on the balance of payments. These aspects of uncertainty are briefly dealt with in Appendix D.

For forecasting energy demand the Board has developed a low case, a middle case, an intermediate case and a high case based on assumptions regarding energy prices and economic growth. The Board is also aware that accurate forecasts are particularly difficult and uncertain when rapid energy substitution is expected to take place. It may be easy to foresee that energy substitutions, such as natural gas for oil as proposed by the NEP, will take place, but it is difficult to forecast the precise timing and extent of substitution.

CHAPTER 2
SUMMARY AND CONCLUSIONS

2.1 Demand for Energy

The Board's forecast of total energy demand in the various sectors and regions is linked to selected economic and population indicators and to energy prices, over the period 1980-2000. The fuel selection process is analysed separately by estimating future market shares.

As in the past, in addition to preparing a middle demand case, the Board also developed alternative cases to provide some perspective on the sensitivity of the energy demand forecast to variances in the major underlying assumptions on energy prices and economic growth.

The middle demand case assumes the most probable base case economic growth forecast and NEP prices for oil and natural gas. The intermediate demand case incorporates a less probable higher economic growth and the same prices as in the middle demand case.

The low and high demand cases use different price assumptions compared with the previous two cases. The low demand case uses 30 percent higher real energy prices, this price change being phased in over a period of five years (1981-85) and the base case economic growth forecast. The high demand case uses 30 percent lower real energy prices, phased in over five years and the higher economic growth forecast.

The demand cases and the changes in the basic assumptions are summarized in Table 2-1.

Table 2-1

NEB ENERGY DEMAND CASES

Demand Case	Economic Activity	Energy Price Forecast
High	High	Low
Intermediate	High	Middle
Middle	Base	Middle
Low	Base	High

For the most part in this report the Board's middle demand case forecast is used. The high and low cases are used along with the middle case, principally in relation to oil, gas and electricity balances. The intermediate demand case, showing an energy demand between the middle and high cases, is only to illustrate the increase in energy demand resulting from high economic growth.

It should be noted that the high and low cases show that demand could be as much as 15 percent higher or six percent lower than the middle case in 1990. However, in what follows in this summary, all further references to demand estimates are to the Board's middle case.

The Board's base case macroeconomic forecast underlies the middle demand case. For the 1980s, the Board's forecast is that growth in real Gross National Expenditure (GNE) averages 3.1 percent per year while inflation, as measured by the Consumer Price Index (CPI), averages a rate of 8.1 percent per year driven by higher domestic energy prices. This modest economic performance prevents the unemployment rate from declining substantially throughout the decade, and it averages 7.2 percent. In the 1990s, real economic growth accelerates somewhat to an annual average rate of 3.4 percent. This, combined with slower labour force growth, causes the unemployment rate to decline, averaging some 6.1 percent over the decade.

The investment sector provides the bright spot of this forecast, both in the medium and longer term. Led by fixed private non-residential investment, particularly in energy-related projects during the 1980s, the investment sector constitutes the main engine of real growth in the next two decades. Investment as a share of GNE increases steadily throughout the forecast horizon, with most of the increase taking place in the 1980s.

The Board forecasts an annual rate of growth in population which declines gradually over the forecast period, from an average annual rate of 1.1 percent during the 1980s to an average rate of 0.9 percent during the 1990s. By the year 2000, the resultant population is 29 million persons.

For its middle demand case, the Board based its domestic crude oil and natural gas price assumptions on the provisions contained in the NEP. For later years of the forecast period judgement was exercised, since the NEP did not include a projection of crude oil and natural gas prices to the year 2000.

As a result of these price assumptions, the Toronto city-gate price of natural gas relative to the Toronto refinery-gate price of crude oil declines from approximately 80 percent to 65 percent by 1984. After 1984, the price of gas relative to oil begins to increase, reaching 74 percent by 1990, and 80 percent by the year 2000.

The forecast of electricity prices to 1984 is based on utility announcements and developed separately for each province. After 1984, electricity prices in each province are assumed to remain constant in real terms.

Based on the above price assumptions, the difference between electricity and fossil fuel prices narrows and in the 1990s electricity is forecast to become the least cost alternative in the residential sector in most regions.

The Board forecasts total primary energy demand in Canada to increase from 10.4 exajoules in 1980, to 12.9 exajoules by 1990, and to 16.2 exajoules by the year 2000, an overall growth rate of 2.3 percent per year. Primary energy demand is summarized in Table 2-2.

Table 2-2

PRIMARY ENERGY DEMAND - CANADA
NEB Middle Demand Case Forecast

	Petajoules					Av. Annual Increase - %		
	1980	1985	1990	1995	2000	1980-1990	1990-2000	1980-2000
Natural Gas[1]	1 820	2 425	2 799	3 090	3 545	4.4	2.4	3.4
Crude Oil[2]	4 068	3 894	3 757	3 904	4 251	–0.8	1.2	0.2
LPG[3]	28	39	93	141	150	12.8	4.9	8.8
Hog Fuel & Pulping Liquor	318	381	448	507	568	3.5	2.4	2.9
Other Renewables	8	10	87	164	267	27.0	11.9	19.2
Coal[5]	1 018	1 144	1 336	1 711	2 051	2.8	4.4	3.6
Hydro & Nuclear[5]	3 096	3 896	4 338	4 573	5 343	3.4	2.1	2.8
Total Primary Energy[4]	10 356	11 789	12 858	14 090	16 175	2.2	2.3	2.3

(1) including ethane
(2) including refinery LPG
(3) gas plant LPG only
(4) does not necessarily add up due to rounding.
(5) hydro, nuclear and 74 percent of the coal (in 1990) is used for electricity generation.

The present forecast of primary energy demand is approximately one percent lower in 1990, and seven percent lower in year 2000, than the forecast that was shown in the November 1979 Reasons for Decision. This lower forecast is generally in line with the evidence presented at this inquiry. It is also the result of a lower forecast of economic activity and of higher domestic energy prices after the mid-1980s than those forecast for the November Reasons for Decision.

The most important change from the November 1979 Reasons for Decision forecast is in the demand for petroleum products and natural gas, mainly as the result of the expected impact of the provisions contained in the NEP.

The present forecast of demand for petroleum products is 17 percent lower in 1990, and 18 percent lower in the year 2000, than the November 1979 forecast. The forecast of demand for natural gas, however, is 6.5 percent higher in 1990 and 3.7 percent higher in 2000.

In the present forecast, the share of crude oil in total primary energy demand declines from 39 percent in 1980, to 29 percent by 1990, and to 26 percent by the year 2000. The share of gas increases from 18 percent in 1980, to 22 percent in 1990, maintaining its share thereafter.

The demand for selected petroleum products is shown in Table 2-3.

The demand for motor gasoline, the largest single oil product category in 1980, is forecast to decline somewhat at the annual rate of one percent up to 1990, and 0.8 percent between 1990 and 2000. This represents a drop in annual demand of some 17 percent by the year 2000, below present demand. Forecast consumer response to gasoline prices and a switching to diesel cause this pattern. The Board also forecasts some conversion in the road transportation sector from motor gasoline to propane, mainly in government and large commercial fleets. The number of propane fuelled vehicles is expected to increase from approximately 8 800 in 1980, to some 145 000 by the year 2000.

Table 2-3

DEMAND FOR SELECTED PETROLEUM PRODUCTS - CANADA
NEB Middle Demand Case Forecast

	Petajoules					Av. Annual Increase - %		
	1980	1985	1990	1995	2000	1980-1990	1990-2000	1980-2000
Motor Gasoline	1 341	1 280	1 212	1 150	1 115	–1.0	–0.8	–0.9
Aviation Fuels	175	206	235	269	332	3.0	3.5	3.3
Light Fuel Oil & Kerosene	607	445	315	245	216	–6.3	–3.7	–5.0
Diesel Fuel	581	709	873	1 031	1 214	4.2	3.4	3.8
Heavy Fuel Oil	626	433	261	254	227	–8.4	–1.4	–4.9
Petrochemical Feedstocks	156	213	221	264	389	3.5	5.8	4.7
Other Products[1]	522	544	574	622	685	1.0	1.8	1.4
Total	4 008	3 830	3 691	3 835	4 178	–0.8	1.2	0.2

(1) Excludes refinery LPG but includes industry own use and losses of all petroleum products.

Rapid declines in demand for light and heavy fuel oils are forecast, particularly in the period to 1990, in the range of six to nine percent per year.

The Board expects the market share of light plus heavy fuel oils in the combined residential, commercial and industrial markets to decline from 24 percent in 1980, to nine percent by 1990, and to five percent by the year 2000. The forecast indicates that the NEP off-oil policy target for light and heavy fuel oils could be met in aggregate by 1990, although not in every sector for every province.

The projected sharp decline in domestic heavy fuel oil demand as a result of natural gas penetration is based on the assumption that surplus heavy fuel oil would be upgraded or exported so that it would not compete with natural gas in the domestic market at depressed prices.

In contrast to the foregoing, demand for diesel and aviation fuels and other products including petrochemical feedstocks are expected to increase at annual rates in the three to four percent range throughout the period to 2000.

Based on the evidence, the Board forecasts an increase of 65 petajoules per year in petrochemical demand for oil between 1980 and 1990. A further 168 petajoules per year of oil for petrochemicals are included after 1990.

The total demand for all petroleum products is forecast to decline at 0.8 percent per year up to 1990, but to increase at about 1.2 percent per year between 1990 and 2000. This results in an annual demand which in absolute terms is some four percent higher by 2000 than in 1980. As summarized, gasoline demand declines gradually over the period, but the significant declines in light and heavy fuel oils are offset in the 1990s by growth in aviation fuels, diesel, and other products.

Natural gas demand is projected to increase at some 3.4 percent per year, and by 1982, gas is forecast to be sold in Eastern Québec. Also, for purposes of this forecast, gas has been assumed to be available on Vancouver Island and in the Maritimes by 1983. New demand is expected to occur in all market sectors with the emphasis on the industrial sector.

The Board forecasts that the demand for electricity will increase from 1 224 petajoules in 1980 to 2 285 petajoules in the year 2000, at an average growth rate of 3.2 percent per year, and the primary energy equivalent of the resources devoted to generation of electricity is expected to increase to some 44 percent of the total primary energy demand by the year 2000.

The production of energy from nuclear and hydro is forecast to increase at an average annual rate of 2.8 percent which is slightly lower than that forecast in the November 1979 Reasons for Decision. By 1990 this production is lower by one percent and by 2000 it is lower by 19 percent. The latter difference, however, results mainly from a forecast of increased use of coal in electrical generation.

The Board forecasts the use of coal for electricity generation to increase at an average annual rate of some four percent and other coal uses to increase at a rate of 1.7 percent. Unlike some Submittors who included large quantities of coal for liquefaction, synthetic gas and for oil sand and heavy crude oil upgrading plants, the Board believes that natural gas supplies will constrain the use of coal for such purposes.

As a result of higher fossil fuel prices, the Board forecasts increased utilization of hog fuel and pulping liquor by the pulp and paper industry. Hog fuel and pulping liquor are expected to provide 3.5 percent of total primary energy by the year 2000, compared to 3.1 percent in 1980.

The Board expects growing utilization of solar energy, especially during the second half of the forecast period. However, even so, by the year 2000 solar energy is projected to supply only between one and two percent of the Canadian primary energy demand.

The Board recognizes that various energy forms such as biomass, other than wood biomass, may begin to contribute towards Canada's energy requirements during the forecast period. However, while use of alternative energies is often technically feasible, their economic viability is not expected to be achieved before the end of the forecast period.

With respect to hydrogen it must be remembered that it is an intermediate energy form produced from primary energy resources. The technology has yet to be developed to a sufficient degree to allow for a full assessment of its potential contribution. At this time hydrogen is not expected to contribute to Canada's secondary energy requirements during the forecast period.

2.2 Energy Supply

Hydrocarbon Supply

Supply forecasts are by nature speculative and subject to widely differing opinions, even among experts, because of major uncertainties concerning geological potential, limitations imposed by production and transportation technologies, and forecasts of future pricing, regulatory and fiscal policies of governments. As in its previous reports, the Board has prepared for each supply category a base case forecast. Underlying the base case are the most probable estimates of geological potential, gradual improvement of known technologies, as well as the pricing and fiscal measures of the NEP, as published in October, 1980, and current provincial regulations and policies. To illustrate the uncertainties surrounding the base case forecast, high and low supply cases have been developed taking into account the extreme or limiting values for each of the supply assumptions.

Because discussions related to the provisions and implementation of the NEP are ongoing between the federal and provincial governments, a modified base case has been prepared for crude oil supply. The modified base case shows the supply which could occur if a pricing and revenue sharing agreement were negotiated by the governments leaving netbacks to investors adequate to aggressively develop oil supplies. Such netbacks could be achieved by changes to prices, royalties, taxes and incentives, or various combinations thereof.

This summary concentrates on the base case and the modified base case.

Crude Oil and Equivalent

A comparison of the Board's current forecasts of productive capacity with that contained in its September, 1978 Oil Report is shown in Table 2-4.

Production during 1980 averaging 245 thousand cubic metres per day was virtually at capacity.

It is often useful to group supply from the above sources into only two categories based on production, transportation and refining similarities. These two categories are light crude oil and equivalent and heavy crude oil as shown in Table 2-5.

The forecasts shown in Tables 2-4 and 2-5 do not include the effect of Alberta's plans to withhold ultimately 28.6 thousand cubic metres per day (180 thousand barrels per day) of light crude oil supply in the absence of an energy pricing agreement. Continuation of such a reduction would reduce available supplies shown above by some 20.1 thousand cubic metres per day in 1985, and 13.7 thousand cubic metres per day in 1995. Reserves not produced in earlier years would add to supply in later years.

Because of the lead time required to obtain supply from new energy projects, the Board believes that productive capacity is not significantly variable in the short term. Available domestic oil supplies are forecast to decline from current levels at about five percent per year until the mid 1980s in both the base case and the modified base case. Major opportunities to increase domestic production are available in the long term from new discoveries, enhanced oil recovery, oil sands and frontier areas.

Canada's established conventional crude oil reserves at the end of 1980 were 745 million cubic metres, the equivalent of about ten years of supply at current production rates. The initial recoverable reserves in known reservoirs were 2 287 million cubic

Table 2-4

PRODUCTIVE CAPACITY OF CRUDE OIL AND EQUIVALENT
($10^3 m^3/d$)

	Actual	1978 Report		Current Report Base Case		Current Report Mod. Base Case	
	1980	1985	1995	1985	1995	1985	1995
Light Crude Oil							
Established Reserves	179.4	96.4	31.2	96.0	32.0	99.7	33.6
Additions:							
Discoveries	—	20.0	17.6	15.1	23.5	15.1	23.5
Enhanced Recovery	—	4.0	13.3	3.4	14.6	3.7	17.9
Heavy Crude Oil							
Established Reserves	33.6	16.5	5.9	17.3	8.6	20.7	7.6
Additions:							
Discoveries	—	7.9	8.4	5.0	8.1	5.0	8.1
Enhanced Recovery	—	4.1	18.0	4.6	16.0	5.3	21.3
Pentanes Plus	16.7	16.2	7.6	16.6	9.5	16.6	9.5
Oil Sands	20.3	40.5	120.0	34.0	34.0	34.0	117.0
Frontier	—	0.0	0.0	0.0	11.8	0.0	13.0
Less: Upgrading Loss	—	0.8	0.8	0.0	1.0	0.0	1.0
Total	250.0	204.8	221.2	192.0	157.1	200.1	250.5

Table 2-5

PRODUCTIVE CAPACITY OF LIGHT AND HEAVY CRUDE OIL
($10^3 m^3/d$)

	Actual	1978 Report		Current Report Base Case		Current Report Mod. Base Case	
	1980	1985	1995	1985	1995	1985	1995
Light Crude Oil and Equivalent	214.0	177.6	189.4	157.9	125.4	161.6	214.1
Heavy Crude Oil	36.0	27.2	31.8	34.1	31.7	38.5	36.4
Total	250.0	204.8	221.2	192.0	157.1	200.1	250.5

metres of which 1 542 million cubic metres had been produced. The fact that Canada has already produced two-thirds of the reserves estimated to be recoverable from known reservoirs has important implications. As more oil is produced from a reservoir the percentage of water in the produced fluid usually increases. Because of the declining oil production per well and increasing water-oil ratios in the mature fields of Western Canada the Board accepts that real operating costs per cubic metre of oil produced will continue to increase faster than the general inflation rate.

With respect to established reserves the Board is concerned that the combination of current federal and provincial policies will not allow producers to optimize production rates from all reservoirs, and that a loss of recoverable reserves could occur as a result. Adjustments to royalties, taxes and prices are required to prevent premature abandonment of marginal producing properties, and to encourage investment in drilling additional wells and installing equipment to handle increasing water production. Examples of these conditions are the Beaverhill Lake reservoirs in Alberta, and heavy crude oil pools in Saskatchewan. In the base case the Board has estimated the loss of oil supply that would occur as a result of the adverse economics that producers will face in some pools. In the modified base case it is assumed that all established reserves are produced at maximum efficient rates.

By 1995, over 60 percent of conventional crude oil supply is expected to come from reserves additions and less than 40 percent from currently established reserves. Reserves additions accrue from two categories, new discoveries and enhanced recovery from known reservoirs.

The Board's assessment of ultimate potential is unchanged from the Board's 1978 Oil Report. The production profiles from new discoveries, however, have been altered to reflect actual reserves additions made in 1979 and 1980, and the Board's new forecast of exploratory activity levels. The forecast of productive capacity from discoveries is the same for both the base case and the modified base case. Higher prices for newly discovered oil would likely increase the rate of discovery, however, the Board has not attempted to quantify this effect.

The Board believes that initiatives aimed at improving recovery from known reservoirs are necessary. Using installed recovery methods, about one-third of the oil in place in conventional light crude oil reservoirs will be recovered before the producing wells are abandoned. The Board expects that another seven to eight percent of the oil in place is technically recoverable if economic obstacles can be overcome and tertiary recovery schemes perform as expected. However, at the NEP price of $189 per cubic metre and existing royalties, incentives and taxes, the Board estimates that recovery levels can only be increased by some two to three percent. If producer netbacks resulting from changes to royalties, incentives, taxes and prices were to be increased by an additional $30 per cubic metre, as assumed in the modified base case, this recovery increase could be doubled. Comparable opportunities are available for increasing the recovery of heavy crude oil.

The pentanes plus forecast which forms part of the crude oil equivalent supply is discussed under the natural gas liquids supply section.

In its base case the Board has not included any new oil sands projects as it believes these schemes are not economic under current pricing and revenue sharing agreements. The Board continues to be of the view that governments can and should establish an economic and regulatory environment that will allow oil sands projects to proceed, and has included an aggressive oil sands development schedule in its modified base case.

At the time of its previous oil inquiry, the Board did not include any frontier oil supplies in its forecasts, believing their inclusion to be too speculative at that time. There have been encouraging oil discoveries during the past two years off the East Coast, in the Arctic Islands, and in the Beaufort Sea. Of these, only Hibernia off the East Coast has been developed to the point where supply can be reasonably anticipated. The established reserves of 50 million cubic metres included by the Board in its forecasts are only those which have been confirmed by the wells completed in the field. Additional exploration is required in the frontier areas before reliable supply forecasts can be made, but much encouragement can be drawn from successes achieved to date.

Natural Gas

Table 2-6 compares the Board's current forecast of gas supply with its previous estimate published in November, 1979.

Table 2-6

SUPPLY CAPABILITY OF NATURAL GAS
(PJ/yr)

	Actual	1979 Report		Current Report	
	1980	1985	1995	1985	1995
Established Reserves	3 800	4 202	1 650	4 139	1 853
Reserves Additions	—	673	1 504	398	1 300
Total	3 800	4 875	3 154	4 537	3 153

Because of lack of markets, only 71 percent of the available capability was utilized in 1980 with production averaging some 2 700 petajoules for the year.

Established reserves of natural gas are estimated by the Board to be 76.2 exajoules as of year-end 1980. At current production rates of 2.7 exajoules per year, this is the equivalent of about 28 years of supply. The Board has made net negative revisions of 1.4 exajoules to previously booked reserves of mature producing pools because of poorer than anticipated production performance. This performance of some mature producing pools is of concern to the Board and continued emphasis will be placed on this aspect of reservoir evaluation in the future.

The Board has not changed its estimate of the ultimate potential for conventional gas since its November 1979 Reasons for Decision. However, because of the current restricted market situa-

tion, and lower than anticipated producer cash flows, the rate of annual reserves additions has been adjusted to reflect a reduced rate of exploratory activity in the early years of the forecast period.

With respect to frontier areas, the Board has left basically unchanged its 1979 estimate of established reserves adding to it two new pools in the Arctic Islands. No attempt has been made to develop deliverability schedules for frontier gas because of the uncertainty associated with development and transportation facilities, threshold volumes, economic viability, and potential markets for the gas. The potential impact of frontier supplies is shown using illustrative scenarios in the supply/demand balance section of the report.

The Board recognizes that a potential exists for future production of non-conventional gas from very low permeability reservoirs. Although Canada has sufficient quantities of conventional gas for the reasonably foreseeable future, it would be helpful to begin now to test these reservoirs to determine what degree of reliance Canadians can place on this source of supply in the future. The Board recognizes that special arrangements may well be necessary if this is to be accomplished.

Natural Gas Liquids

The Board has not previously published a long-term forecast of NGL production although the pentanes plus portion has been included in the Oil Reports. Table 2-7 summarizes the Board's current forecast.

Table 2-7

PRODUCTION OF NATURAL GAS LIQUIDS
($10^3m^3/d$)

	Actual	Current Report	
	1980	1985	1995
Ethane	13.0	26.1	18.4
Propane	20.1	21.8	14.8
Butanes	12.5	13.4	9.2
Pentanes Plus	17.2	17.0	9.9
Total NGL	62.8	78.3	52.3

Natural gas liquids are produced as a by-product of gas treated at gas plants and gas reprocessing plants, and as a by-product of crude oil refining. The NGL must then be stored in inventory or sold immediately into the domestic or export market. The NGL forecast is therefore tied directly to the oil and gas forecasts summarized in the preceding two sections. The forecasts do not include any potential supplies from frontier areas nor recovery of liquids at future oil sands projects.

Electricity Supply

Except for the United States coal supplied to Ontario Hydro and small quantities of imported oil and some natural gas, the primary resources used to generate electricity are indigenous hydroelectric power, coal and uranium.

New electricity generating facilities for the 1980s, and in some cases into the 1990s, are already committed. Hydroelectricity's proportion of the total Canadian production of electricity will decrease from 68 percent in 1980 to 56 percent by the year 2000 although increasing in absolute terms by 52 percent. Coal's share of electricity supply will increase from 15 percent to 23 percent and nuclear energy's share will increase from 10 percent to 17 percent.

Newfoundland, Québec, Manitoba and British Columbia will continue their emphasis on hydroelectricity. Nova Scotia, Saskatchewan and Alberta will expand their electricity production using indigenous coal. Ontario and, to a lesser extent, New Brunswick will add nuclear capacity. Prince Edward Island will continue to be heavily dependent on its underwater cable interconnection with New Brunswick. It is expected that the current dependency on oil for electricity generation in the Atlantic Provinces will be decreased if studies now under way confirm the advantage of converting oil-fired generating plants to coal.

The electricity supply industry is capital-intensive, with generating plant construction costs up to $2 600 per kilowatt (in 1980 dollars). No difficulty is anticipated in finding the capital necessary to fund generation expansion programs and the transmission and distribution facilities to bring electricity to the customers.

Existing technology is adequate for system development, and with adequate lead times, environmental concerns can be satisfied. The Board, therefore, sees no obstacle to meeting electricity demand over the period 1980-2000.

Unconventional renewable resources such as wind and solar energy will only make a minor contribution to total supplies but important contributions in isolated areas.

It has been suggested that electricity should not be used to meet demands which can be supplied by other forms of energy, e.g. residential heating. However, it should be noted that electricity can be generated from readily available primary resources often unusable in any other way and is highly flexible in meeting a wide range of end uses.

Coal Supply

The Board believes that current reserves plus potential reserves additions from the resource base will be sufficient to meet Canadian requirements for indigenous coal plus provide coal to the export market during the forecast period.

Other Energy Forms

The supply of hog fuels, solar energy and other renewables have the potential to reduce the demand for other energy forms. However, they are not expected to contribute significantly to Canada's net energy balance without technological breakthroughs to make the economics of supply more favourable.

2.3 Supply/Demand Balances

Crude Oil and Equivalent

Balances of the middle demand versus the base case supply and the modified base case supply are shown in Tables 2-8 and 2-9 respectively.

Table 2-8 shows that for middle demand and base case supply, Canada's net imports would continue to grow throughout the forecast period at an average rate of about six percent per year. By the late 1980s there would be insufficient western crude oil to operate the Sarnia to Montreal pipeline, and by the late 1990s domestic oil would no longer be available for Ontario refineries. Means would have to be sought to provide additional imported crude oil to the refining centres in Québec and Ontario in these circumstances.

Table 2-8

SUPPLY/DEMAND BALANCE FOR CRUDE OIL AND EQUIVALENT
Middle Demand versus Base Supply
($10^3m^3/d$)

	1980	1985	1990	1995	2000
Production	245	192	179	157	123
Requirements	300	287	271	280	306
Net Imports	55	95	92	123	183
Exports(1)	15	7	3	0	0
Total Imports	70	102	95	123	183

(1) Heavy crude oil estimated to be surplus to domestic requirements in Montreal and West.

Table 2-9 shows that for middle demand and modified base case supply, imports would increase initially but would then decline for the remainder of the forecast period, representing less than nine percent of Canadian requirements by the year 2000. This represents an improvement over Canada's current oil import situation and no new importing facilities would be required during the forecast period.

Table 2-9

SUPPLY/DEMAND BALANCE FOR CRUDE OIL AND EQUIVALENT
Middle Demand versus Modified Base Supply
($10^3m^3/d$)

	1980	1985	1990	1995	2000
Production	245	200	230	251	282
Requirements	300	287	272	281	306
Net Imports	55	87	42	30	24
Exports(1)	15	12	4	2	0
Total Imports	70	99	46	32	24

(1) Heavy crude oil estimated to be surplus to domestic requirements in Montreal and West.

The Board is not forecasting oil self-sufficiency in either of the above cases, however, it believes that such an objective is attainable given the appropriate conditions for lower demand and higher supply.

Although Canada will likely remain a net importer of crude oil and equivalent, it has excess productive capacity of heavy crude oil and large deposits of heavy crude oil remain to be developed. Means should be developed to increase use of heavy crude oil in Canada. Until these means, such as heavy crude oil upgrading, are developed it will be necessary to offer producers the opportunity for export sales.

Natural Gas

The Board has decided not to make any changes at this time to the procedures used in the determination of natural gas surplus. For illustrative purposes the Board has calculated its three surplus tests taking into consideration the middle demand and authorized exports, the supply from established reserves, and where appropriate, the deliverability from the base case reserves additions. In these examples the Current Deliverability Test is the most restrictive and shows that there does not appear to be any surplus available at this time to support new exports of natural gas from the reserves included for purposes of surplus determination in this report. The Future Deliverability Test using the base case reserves additions shows that domestic demand plus exports could be met until 1998.

The Board has also used its three demand and three supply cases to illustrate the sensitivity of the natural gas supply/demand balance and to illustrate when additional supply may be required from frontier resources. The balance for base case supply and middle demand shows that frontier supplies of natural gas are not required for domestic use before 1998. However, in the extreme situation of high demand and low supply, additional supply could be required as early as 1992.

Natural Gas Liquids

The supply of natural gas liquids depends on the supply and demand for crude oil and natural gas. On the basis of the Board's base case supply and middle demand there exists the possibility that the supply of ethane and propane will not be adequate to meet demand in the later years of the forecast period. However, additional extraction capability could be available from new oil sands plants, frontier areas and from possible new reprocessing facilities in British Columbia.

Coal

Canada has large potential coal resources which could be developed, but the demand for coal is expected to be small in comparison to the potential supply. By the end of the forecast period Canadian demand for coal is expected to be approximately double the quantity now consumed. Canada is expected to be a net exporter of coal over the forecast period.

Electricity

Canadian utilities currently have surplus capacity available because plants committed during the higher load growth period prior to 1974 are now coming on line. Even after capacity more closely approaches the annual peak demand plus required reserve, Canadian utilities will still have the capability to generate electricity surplus to Canadian demand, especially during off-peak periods. Since generation costs in Canada are generally lower than in the United States, the Board expects that the export market for Canadian electricity will continue to be strong. These exports will give significant revenues to Canadian utilities. The value of electricity exports now comes close to $1 billion annually.

The Energy Perspective

At present Canada enjoys a favourable trade balance in energy which, since 1975, has been increasing in spite of the phasing out of light crude oil exports. Large natural gas exports, valued at some $4.0 billion annually, and the increasing value of electricity exports, of about $0.8 billion in 1980, to the United States, have offset growing oil import payments to other countries.

While in recent years Canada's natural gas surplus has permitted the granting of new gas exports licences, these are for a limited period. Although the value of electricity exports is expected to increase, and the trade balance in coal to improve, the Board's base case oil supply forecast suggests that oil imports would double by the early 1990s when Canada could become a net importer of energy.

Thus, in considering the energy perspective, one is led back to the question of self sufficiency in oil.

There is little doubt that Canada has the oil supply potential to phase out oil imports. Under the modified base case supply, oil imports are forecast to be held in check during the 1990s. Further reductions in domestic oil products demand, particularly motor gasoline, could also be achieved with higher oil product prices than projected in the Board's middle demand forecast.

2.4 Conclusions

The main conclusions of this report are:

Demand

1. Primary energy demand in Canada is forecast to increase from 10.4 exajoules in 1980 to 16.2 exajoules by 2000, representing an average growth rate of 2.3 percent per year.

2. The following are the major differences between the present forecast and the Board's forecast published in the November 1979 Reasons for Decision.

   (i) the present forecast of primary energy demand is one percent lower in 1990, and seven percent lower in 2000.

   (ii) the present forecast of demand for petroleum products is 17 percent lower in 1990, and 18 percent lower in 2000.

   (iii) the present forecast of natural gas demand is 6.5 percent higher in 1990, and 3.7 percent higher in 2000.

3. Total demand for all petroleum products is forecast to decline at 0.8 percent per year up to 1990, but to increase at 1.2 percent per year between 1990 and 2000. This results in an annual demand which in absolute terms is some four percent higher by 2000 than in 1980. The decline in total demand during the 1980s is mainly the result of the rapid displacement of light and heavy fuel oils by natural gas, the bulk of which takes place during that period.

4. The market share of light plus heavy fuel oils in the combined residential, commercial and industrial market is forecast to decline from 24 percent in 1980 to nine percent by 1990 and to five percent by 2000. The forecast indicates that the NEP off-oil policy target could be met in aggregate by 1990, although not in every sector for every province.

5. Demand for motor gasoline, the largest single oil product category, is forecast to decline at an annual rate of 0.9 percent between 1980 and 2000, a drop in demand of 17 percent below present demand by 2000. The decline is the result of higher gasoline prices and of some conversions to diesel and propane.

6. In contrast, diesel and aviation fuels and other products including petrochemical feedstocks, are expected to increase at annual rates in the three to four percent range throughout the period to 2000.

7. Demand for natural gas is forecast to increase at 3.4 percent per year. For the purpose of the Board's forecast, gas has been assumed to be available in Eastern Québec by 1982, and on Vancouver Island and in the Maritimes by 1983.

8. As a result of the Board's price forecasts, the difference between electricity and fossil fuel prices narrows and in the 1990's electricity is forecast to become the least cost alternative in the residential sector in most regions.

9. Demand for electricity is forecast to increase at an average rate of 3.2 percent per year, and energy from nuclear and hydro for electrical generation is forecast to increase at an average annual rate of 2.8 percent during the forecast period.

10. The use of coal for electricity generation is forecast to increase at an average annual rate of four percent and other coal uses at a rate of 1.7 percent. The Board's forecast does not include the use of coal for liquefaction, synthetic gas or for oil sands and heavy crude oil upgrading plants.

Supply & Supply/Demand Balance

Hydrocarbons

1. With respect to natural gas, supply from currently established reserves will be adequate to meet most domestic and export requirements for the next ten years. However, minor deficiencies are indicated in several years starting in 1985 if exports are delivered at full licenced volumes.

2. If reserves additions in the conventional producing areas occur as forecast by the Board, it is likely that frontier gas will not be required to serve domestic markets until 1998.

3. Although Canada appears to have adequate supplies of conventional gas for the foreseeable future, it would be desirable to assess the technology and economics of producing gas from non-conventional sources.

4. Natural gas liquids, which are a by-product of gas production and processing, will remain in a surplus position until the late 1980s. Deficiencies could occur after that if NGL supplies are not made available from oil sands plants, frontier gas supply developments, or extraction facilities in British columbia.

5. Producer netbacks must increase if Canada is to approach oil self-sufficiency within the forecast period. Without increases, net imports will grow at an average of six percent per year.

6. New oil sands plants will require a price in the range of $260 to $300 per cubic metre in real terms if these plants are to proceed. The NEP oil sands price is $239 per cubic metre. With proper incentives, the oil sands could be supplying more than one half of our domestic production by the end of the forecast period.

7. The application of tertiary recovery methods has the potential to make a significant contribution to oil supply over the longer term. However, even with substantial increases in producer netback, the need to develop and demonstrate the technology, and the availability of injection fluids, will control the rate of implementation in this decade.

8. Frontier oil and gas exploration would proceed more expeditiously if uncertainties relating to pricing and jurisdiction were removed. Exploration success off the east coast, in the Arctic Islands and in the Beaufort Sea suggests large oil and gas potential for the frontier areas.

9. Current prices and fiscal policies for conventional oil do not allow producers to maximize production within good engineering and production practices in some pools and some permanent loss of reserves could occur as a result.

10. The Board notes that estimates of industry netbacks required to achieve the Board's supply forecasts depend heavily on future costs and rates of cost escalation and these are very difficult to estimate given the dramatic cost increases experienced by the industry in the past several years. The escalation in capital and operating costs experienced by the petroleum industry could, if continued into the future without moderation, severely limit the development of new oil supplies. The factors underlying the industry's increases in capital and operating costs during the past several years should be further analyzed to determine what moderating action can be taken by industry and governments.

Electricity

I. During the period 1980-2000 electricity is expected to be in good supply using readily available indigenous primary resources plus United States coal (in Ontario).

2. Prices for electricity are expected to remain stable in terms of constant dollars and electricity's share of the total market for energy will continue to increase.

3. Given adequate lead time electricity could supply a larger share of energy demand than forecast by the Board. The pursuit of such a policy option would, however, entail some upward pressure on the real price of electricity.

4. United States' demand for Canadian electricity exports to displace oil-fired generation will continue to be high. These exports will give significant revenue to Canadian utilities.

CHAPTER 3
OVERVIEW OF ENERGY ISSUES

3.1 Outline of the National Energy Program (NEP)

The NEP, announced with the federal budget on October 28, 1980, introduced a significant new factor into the Board's Total Energy Inquiry. Submittors were given the opportunity to evaluate the impact of the new policy on information previously filed, and to present their related views. Many supplementary submissions and extensive testimony during the hearing commented on the significance of the NEP and estimated its impact on Canada's energy future.

A brief outline of the NEP is presented in Appendix E covering the following major provisions:

a) New Taxes and Income Tax Changes,
b) Energy Prices,
c) Energy Supply Incentive Programs,
d) New Legislation — Canada Lands,
e) Oil Substitution Measures,
f) Energy Conservation Measures,
g) Electricity in the Atlantic Regions.

Views of Submittors on the Impact of the NEP on Energy Supply

Objectives of the NEP

Most Submittors were in agreement with the stated objectives of the NEP, namely, security of energy supply, opportunity for Canadian participation in the industry, and fairness with respect to pricing and the sharing of revenues. There was, however, disagreement expressed by Submittors with the measures proposed to achieve the objectives and the apparent priority attached to the objectives. The major concern was that the NEP placed a high priority on increasing Canadian participation in the industry and restructuring the respective revenue shares of governments and industry while reducing the probability of achieving self-sufficiency.

Cash Flow

The first area of concern to most Submittors was the establishment of new oil and gas taxes, less favourable income tax treatment and the setting of prices at levels below previous expectations, at least in the first few years. These factors combined to reduce the cash flow of oil and gas producers. Some Canadian companies such as Husky and Norcen which expected to qualify for grants under the Petroleum Incentives Program felt that the grants would offset some of the effects of the new oil and gas taxes while Petro-Canada, with large frontier investments, expected incentives to more than compensate for the NEP cash flow reduction.

Most Submittors indicated that the NEP would hold a company's 1981 cash flow from oil and gas production at, or slightly below, actual cash flows for 1980. The reduction from pre-NEP forecast conditions depended upon each company's perception of how fast prices would have gone up. A reduction of some 25 percent in cash flow from oil and gas production for 1981 compared to previous expectations was indicated as an industry average. In calculating their estimates of cash flow reduction, most Submittors excluded revenues from operations other than oil and gas production. Most Submittors also excluded incentive payments from the cash flow analysis as the payments in their view represented a reduction in exploration and development costs rather than an increase in operating revenue.

Oil and Gas Wellhead Prices

Most Submittors found the conventional oil price schedule and the natural gas wellhead prices presented in the NEP to be below previous expectations. Petro-Canada and Norcen indicated that the more rapid price escalation in the later 1980s met or exceeded their expectations.

Several Submittors felt that the oil sands price contained in the NEP was not sufficient to promote further oil sands development. Their main concern was that historical cost increases have exceeded the Consumer Price Index (CPI) which is used to escalate the oil sands price. As future cost increases were expected to continue to exceed the CPI, Submittors felt that an index which was based on oil sands cost experience should be used to escalate prices. Suncor noted that the application of the conventional oil price to production from its original plant would discourage investors from undertaking future oil sands investments.

Most Submittors were encouraged by the NEP provision of a higher price schedule for tertiary oil. Submittors felt, however, that much of the short-term price supplement was taken up by the NEP tax changes, and that the price schedule did not provide the incentive necessary to undertake these long-term, high risk projects. Submittors also noted that there was no definition in the NEP to indicate the oil which would qualify for the tertiary incentive price or at what stage of production the price would be paid. Submittors indicated that only a few of the better tertiary projects in Alberta were considered to be economic with the NEP prices and taxes.

Submittors who were considering exploration and development expenditures in the frontier areas were concerned that no frontier price schedules were contained in the NEP. Before significant commitments would be made for the development of discoveries in the Beaufort Sea and off the east coast, participants in those projects indicated that a frontier oil price must be established and that such a price would need to be higher than the conventional oil price.

Exploration and Development Investment

Submittors addressed a number of factors which would affect the level of investment by the oil and gas industry and exploration activity in particular. Submittors stated that the lack of immediate markets for natural gas, the economic attractiveness of United States exploration, and the negative impact of the NEP, particularly on companies which do not qualify for incentive payments, would result in forecast exploration reductions of from 20 to 50 percent in Western Canada.

Several Submittors noted that the low return available from British Columbia gas production and Saskatchewan oil production would cause large reductions in exploration investment in those areas.

Companies such as NOVA, Norcen, Dome and Petro-Canada which would likely qualify for the higher levels of incentive payments in the frontier areas, indicated that these would encourage future increased frontier investments. On the other hand, those companies that may not qualify, foresaw a reduction in frontier exploration activity, although they did acknowledge that existing long-term commitments and large investments would limit their ability to make immediate changes. Many Submittors felt, however, that the net effect would be a reduction in frontier exploration activity, as only a limited number of companies which qualify for the higher levels of incentive payment have the financial capability to undertake the major investments required for frontier exploration programs. Most Submittors saw the federal government option to take a 25 percent interest in frontier discoveries as detrimental to future frontier exploration.

A study of natural gas exploration economics, prepared by TCPL and Petro-Canada, had anticipated, prior to the NEP, that the lack of immediate markets for natural gas would reduce exploration in Western Canada by 13 percent over the period 1981 to 1985 relative to 1980. Submittors felt that the new taxes, the relatively low natural gas price schedule and the disqualification of shut-in gas wells for exploration expense treatment under the Income Tax Act would exacerbate the reduction in natural gas exploration, even though the NEP did introduce programs to accelerate the development of domestic natural gas markets and proposed a $400 million natural gas bank. Submittors felt that these programs would not have a major impact in view of the large volume of shut-in gas.

Submittors indicated that a number of factors limited their ability to modify previous exploration plans. The main constraint was the drilling requirement associated with maintaining exploration rights. In order to maintain their land positions, companies indicated that they would fulfill drilling obligations. Petro-Canada noted that the new legislation for Canada Lands contained provisions for increased frontier drilling obligations. Some Submittors felt that the flexibility of companies to change exploration plans was constrained by obligations with respect to joint exploration programs and by drilling rig contracts. The Canadian Association of Oilwell Drilling Contractors anticipated that there would be a downturn in exploration plans following the NEP and this would result in drilling rig contracts being terminated. CAODC indicated that most drilling rig contracts in Western Canada could be terminated within ninety days.

Views of Submittors on the Impact of the NEP on Energy Demand

Most Submittors expected that the major impact of the NEP on energy demand would be to increase the substitution of natural gas and electricity for fuel oil. The degree of this increased substitution varied among Submittors depending on the original assumptions underlying their pre-NEP forecasts. For example, Imperial which had anticipated programs and policies similar to those contained in the NEP expected little impact on its demand forecast. Petro-Canada, on the other hand, indicated significant reductions in oil demand as a result of the NEP.

One of the stated goals of the NEP is to reduce oil consumption to no more than ten percent of total energy use in each of the residential, commercial and industrial sectors in every province. Most Submittors which provided supplemental forecasts or comments expected that this goal would likely be reached on a national basis in the commercial sector by 1990. However, opinions were less optimistic with respect to the residential and industrial sectors. Approximately one-half of the Submittors expected that the goal would be attained nationally in the industrial sector by 1990, while none of the Submittors expected the goal to be attainable in the residential sector by 1990.

With respect to the priority in the NEP to replace existing oil-fired generating capacity in the Atlantic region by lower cost alternatives, New Brunswick and Nova Scotia indicated that studies were under way in respect to conversion of 1 600 MW of oil-fired generation to coal. Newfoundland stated that any study of conversion would await the resolution of questions surrounding the development of Labrador hydro power.

With the exception of Petro-Canada, Submittors generally stated that the NEP would have little or no effect on petrochemical demand for oil. Most Submittors viewed the NEP provision of holding petrochemical demand for oil in 1990 to current levels as unrealistic. The major reason given for this view was the non-substitutable nature of certain oil products in petrochemical demand.

Those Submittors which provided supplemental forecasts of total transportation demand after the announcement of the NEP showed reductions ranging between 2 percent and 20 percent in 1990 and 3 percent and 15 percent in 2000. The major reduction in transportation demand was made in the road sector.

3.2 Provincial Submissions

Introduction

Eight Provincial Governments and the Government of the Northwest Territories made submissions to the Board. Alberta and Prince Edward Island did not participate in the Hearing. While Ontario presented supply and demand forecasts, and the Government of the Northwest Territories provided details concerning exploration and development activities, neither Government discussed policy matters.

British Columbia

British Columbia stated that it is committed to shifting energy usage away from oil by encouraging the use of natural gas and other fuels. One element of this policy has been to endorse the construction of a natural gas pipeline to Vancouver Island.

While British Columbia has a substantial surplus of natural gas, it faces the same problems in oil as the nation as a whole. To encourage the increased production of oil, the provincial oil royalty system provides for a reduction in royalty rates for upgraded secondary recovery projects. No royalties are charged on incremental oil production from tertiary pilot projects. Moreover, the Province is prepared to subsidize such schemes.

British Columbia maintained that an export market for natural gas is required at the present time if the exploration, production and transmission industry in the province is to continue to serve the Northwest Pipeline system in the United States Pacific Northwest.

British Columbia expressed its commitment to the principle of replacement cost pricing as the basis for pricing energy in the province. However, it was of the opinion that Canadian oil prices should be rising toward a level that would make Canada self-sufficient in oil.

British Columbia stated that it will depend on hydroelectric generation to supply an increasing share of its energy needs, and will encourage industry to develop co-generation projects for the joint production of process steam and electricity. The Province indicated that it endorses short term exports of temporary surpluses of electricity.

Saskatchewan

Saskatchewan maintained that the off-oil policy of the NEP is not suitable for Saskatchewan. Saskatchewan is already close to the ten percent target for the residential sector. Almost all Saskatchewan residents to whom gas has been made available have taken advantage of this alternative fuel source. It was suggested that an off-oil program appropriate to Saskatchewan would provide assistance to the most important and vulnerable industry, agriculture, and to the highest oil-consuming sector, transportation.

Saskatchewan's preliminary analysis of the impact of the NEP indicated that the Province's forecast of oil producibility from established reserves, provided to the Board in September, 1980, would have to be revised downward for two reasons:

1) The new fiscal arrangements will cause premature abandonment of marginal wells, since the netback for these wells could fall below the economic minimum, and
2) Production cutbacks will lower the effective recovery rate from a given reservoir. This will be especially true for the Lloydminster heavy oil area.

Saskatchewan forecast that with relatively lower producer netbacks there would be no incentive for producers to appreciate existing reserves or to explore for new reserves.

Saskatchewan stated that the tertiary supplement on the wellhead price would be offset by changes in the tax system and the imposition of the petroleum and natural gas revenue tax, to the point that the economics of tertiary production would not be any better than that of conventional production.

Saskatchewan also singled out the importance of conservation initiatives and the need for government programs to encourage their development.

Manitoba

Manitoba stated that it supported the expansion of the domestic natural gas system to serve as many Canadians as possible wherever it is economic.

With respect to petroleum, Manitoba would like to see less crude oil and its products exported as a way to achieve self-sufficiency. It was suggested that there exists no surplus oil to export, and that preference should be given to the domestic use of Canada's energy resources.

Manitoba plans to generate more of its future electrical energy needs from hydro stations, exporting surplus energy either to the Western Provinces or to the United States. Manitoba pointed out that in 1979 it had instituted a policy of freezing domestic electricity prices for five years. This pricing policy is expected to make electricity progressively more competitive with other energy sources.

Québec

Québec expressed concern with the availability of crude oil for its petrochemical industry. Québec agreed with the NEP approach to domestic oil pricing in that the price of crude oil would not be permitted to exceed 85 percent of the international price or the average price in the United States. However, it did not support the NEP's intention to restrict the consumption of crude oil by petrochemical firms in Eastern Canada. Québec pointed out that its petrochemical industry, well established in the province, uses by-products derived from both natural gas and crude oil and that gas cannot produce all of the by-products that are required. Therefore, if the NEP position is maintained, additional demand for by-products would have to be supplied from imports, creating a competitive disadvantage for dependent industries. Industries dependent upon petrochemical products number from 450 to 600 firms, with approximately 15,000 employees.

Québec referred to its White Paper on Energy, published in 1978, and to the views it had expressed at previous NEB hearings. These views represent its general objectives with respect to the demand and supply of all forms of energy including electricity. Québec affirmed that it has no new data to submit in these areas.

New Brunswick

New Brunswick stated that the NEP is not very specific as to what will happen to natural gas pricing after 1983. It was suggested that people who convert their residences to gas become

more or less captive to that system and would therefore want to be sure that the price was going to remain competitive for a large part of the life of the furnace. New Brunswick pointed out that no such assurance exists in the NEP.

New Brunswick recommended that energy conservation be a cornerstone of federal energy policy and urged close consultation with the provinces in this area.

New Brunswick said the supply side of any national energy policy should encourage the maximum use of competitive indigenous sources of energy towards the achievement of both national self-sufficiency and degrees of provincial or regional self-reliance. New Brunswick suggested that the federal government should play a more active role in assisting the development in the province of such energy resources as oil shales, coal, peat, wood and wood waste and tidal power.

New Brunswick plans to make more use of indigenous resources for electricity generation. It is also studying conversion of oil fired stations to coal firing, and supports continuing export of electricity to the New England States.

Nova Scotia

Nova Scotia energy policy stresses the use of indigenous resources other than oil wherever technically and economically feasible. The Province is committed to the NEP's off-oil policy. It also cited as essential, the immediate access to Western Canadian natural gas. It argued that the availability of such gas would be compatible with any potential offshore gas development.

Nova Scotia stated that its policy for electric power generation will be based on coal, and will require further development of domestic resources. However, without the construction of new coal mines, future coal production would be constrained. Conversion of existing oil-fired stations to coal is consistent with this policy and the NEP.

Nova Scotia also singled out the importance of conservation initiatives and the need for government programs to encourage their development.

It was recommended that federal action be taken to assist in the rationalization of the oil refining industry to provide greater proportions of lighter transportation fuels and reduced amounts of residual oil.

Newfoundland

Newfoundland considered that the economic future of the province was closely linked to the development of its offshore hydrocarbon and other energy resources. An early flow of revenue from offshore production would do much to boost its economy. In addition, Newfoundland's electric power policy foresees the development of hydro resources in Labrador, with energy transmission to supply the Island, and with sale of any surplus to other provinces or U.S. utilities. Newfoundland tabled a request to the Board to study and review possible action concerning the extraprovincial transmission of Labrador surplus power. It was pointed out that the province exports about 90 percent of the hydroelectricity it generates, with all of its exports going to Québec from Churchill Falls. Newfoundland argued that when negotiating export contracts it has been placed in a 'take it or leave it' position by the Québec government and that Newfoundland must sell to Québec on whatever terms Québec is prepared to offer. Newfoundland suggested that the terms and conditions governing the interprovincial transfer of electricity should be set by the Board under the NEB Act in the same manner that the Board regulates the interprovincial movement of oil and gas. It was stated that such action may be the deciding factor in determining whether or not Newfoundland's hydro potential is developed.

Newfoundland also contended that it is important to see a proper pricing regime in place. The Province suggested that Canadian oil prices should be increased over the next few years towards approximately 85 percent of world prices.

Newfoundland requested that it be viewed by the Board as a region separate from the Maritime Provinces because of its unique position in Eastern Canada with respect to hydroelectricity and offshore oil and gas. More generally, Newfoundland stated that it sees no merit and much confusion in the present federal practice of aggregating economic, energy and other data relating to 'Atlantic Provinces' and submitted that the federal data system should recognize that these provinces are all quite different and that they should be treated as such.

PART II

DEMAND FOR ENERGY

CHAPTER 4
METHODOLOGY AND ECONOMIC AND PRICE FORECASTS

4.1 Introduction

To examine the future of energy demand in Canada, Submittors were encouraged in the Outline for Submissions to present estimates within a total energy context. It was recognized that many Submittors might prefer to present estimates for only a part of the total energy spectrum, i.e. for selected energy forms, for a specific market area, or for a specific market sector. All such specific forecasts were welcomed.

Submittors using the total energy approach were requested to provide a breakdown of Canadian energy demand by fuel type, including renewable energy, for the different market sectors and for the various geographical areas. They were requested to specify their assumptions with respect to such factors as economic growth, population growth, relative prices of various types of energy, market shares, expansion of energy forms into new markets, and any other assumptions which might have had a bearing on the demand forecast.

Of the 96 Submittors, 42 provided information on demand, and many of these provided forecasts as well. Some Submittors who provided demand estimates presented specialized forecasts of the market sectors or products with which they were primarily concerned. These included some producers, transmittors and distributors of specific energy forms. Others presented forecasts of all energy forms within certain geographical areas, and these included seven of the provincial governments. Still others presented forecasts of all energy forms for Canada as a whole as well as for individual provinces. These included, in general, the major Canadian producers and marketers.

This chapter contains a discussion of the techniques used by the Submittors and the Board in forecasting energy demand, as well as the major economic, demographic, and energy price assumptions that were employed. The following chapters examine the forecasts of total primary Canadian energy demand, energy demand by sector, and the demand for specific energy forms.

4.2 Methodology

Views of Submittors

Virtually every Submittor differed in the specific methodology of forecasting energy demand. For this reason, no attempt is made to provide an all-encompassing discussion of their methodologies, although a brief description of the approaches used is provided below.

Econometric Model Forecasting

Econometric models were most widely used by those Submittors forecasting energy demand for all energy forms, for all market sectors, and for all geographic areas. Most Submittors using this methodology forecast total energy demand by market sector and by province or region. The demand for specific energy forms in each market sector and each province or region was then estimated through the application of market share analysis.

Historical relationships between energy demand and economic, demographic, and price factors were established. Energy demand forecasts were then based on macroeconomic forecasts of these economic, demographic, and price variables. The majority of the Submittors using this method also accounted for the effects of energy conservation on future energy demand. Market share projections were generally based on such factors as historical market shares, expected price competition, the availability of specific energy forms, and the suitability of energy forms in specific market sectors.

Deterministic Model Forecasting

Deterministic models were most widely used by those Submittors forecasting the demand for a specific energy form within a province or specific market area. This approach was used by natural gas distributors and some electric power utilities. The general method followed was to first establish the total number of potential customers and then to multiply it by an average use per customer to forecast energy demand in each market sector. Energy conservation effects were generally taken into account by reducing the average use per customer.

The specific methods which were followed differed for many Submittors and generally for each market sector. In the residential sector, three methods of establishing the number of potential customers were used: the number of existing customers was taken as a base and projected into the future allowing for population growth and additional market penetration; penetration rates were applied to forecasts of population or households; building count surveys were projected into the future based on population projections.

For small commercial customers, the number of accounts was usually projected using one of the above methods or by assuming that the number of commercial customers was some fixed proportion of the number of residential customers.

For the large commercial and industrial sectors, forecasts were based on market surveys or on the extrapolation of current demand into the future.

Other Methods

In addition to econometric and deterministic model forecasting, a number of other methods were used by Submittors to forecast energy demand. For example, several Submittors predicted the demand for petrochemical feedstocks based on the industry's current capacity plus expected additions to capacity. Pétromont, Petrosar and Union Carbide followed this approach. The Province of British Columbia used a detailed engineering-

economic method, similar to a deterministic model, to forecast energy demand for all fuels and all sectors within the province. Ontario Hydro employed the 'current-load forecasting method', whereby the short-term forecast was based on customer and staff survey information and the long-term forecast on an econometric model, to forecast electricity demand in the province of Ontario. The forecast of IGUA was based on survey information provided by its members.

Views of the Board

In developing estimates of Canadian energy demand, the Board uses a total energy forecasting methodology, which is mainly an econometric approach. Energy demand in the residential, commercial, and industrial sectors of each region is linked, in an econometric model, to economic and demographic variables and to energy prices. Market share forecasts are applied to the estimated total energy demand in each sector to yield the demand for each energy form in each region of Canada. The market share forecasts are developed taking into account historical and current trends, expected changes in relative prices, and other factors.

In the transportation sector, demand is estimated separately for each of the air, rail, marine, and road transportation modes. Separate estimates are made for the non-energy use of hydrocarbons, including the demand for petrochemical feedstocks. The forecast of energy requirements for the generation of electricity is based on an analysis of each electric utility and its future plans.

There is uncertainty associated with any forecast, and in particular with long-range forecasts of energy demand. The three factors which are important determinants of the overall level of energy demand and the degree of interfuel competition are the pace of economic activity, the level of energy prices in comparison with the general level of prices in Canada, and the relative prices of competing energy forms. The Board has prepared, as its best estimate, a middle case forecast based on the NEP. In recognizing the uncertainties inherent in forecasting the level of economic activity and energy prices over a twenty-year horizon, the Board has adopted a method of estimating ranges rather than relying on 'point' forecasts. Therefore the Board has also prepared one low demand case and two higher demand cases termed 'intermediate' and 'high'. Detailed presentation of the results is restricted to the middle case for practical considerations. A brief discussion of the high and low demand cases and the corresponding assumptions can be found in Chapter 5.

4.3 Economic and Demographic Projections

Views of Submittors

The general consensus among those Submittors who prepared Canada-wide forecasts was that population growth and overall economic growth would both proceed at a slower pace during the forecast period than had been experienced during the 1960s and early 1970s. The lower rate of economic growth was attributed in large part to declining labour force growth and sluggish rates of productivity gain. The slow-down in population growth reflected expected lower levels of net immigration and fertility rates below the replacement level of 2.1 children per female of child-bearing age. Submittors' forecasts of growth in real GNP, population, and number of households are summarized in Tables 4-1 to 4-3.

Several Submittors forecast regional or provincial economic and demographic growth. Most expected that regional or provincial economic growth rates would be lower than in the past, except for the Atlantic Region* where increased exploration and development of east coast offshore petroleum and natural gas resources were anticipated. They also expected a continued shift in economic activity to Western Canada.

Table 4-1

REAL GROSS NATIONAL PRODUCT - CANADA
GROWTH RATES
Comparison of Forecasts
(Percent per Annum)

	1980-1985	1985-1990	1990-1995	1995-2000
CPA	3.8	3.4	3.5	3.4
Gulf	3.0	3.0	3.0	3.0
Imperial	3.2	3.6	2.8	2.8
IGUA	3.5	3.5	3.5	3.5
Norcen(1)	3.0	3.5	3.5	3.5
NOVA(2)	3.5	3.5	—	—
Petro-Canada(2)	3.3	4.3	3.7	3.2
Petrosar	3.0	3.0	3.0	3.0
Shell	3.4	3.5	3.0	2.8
Texaco	3.1	3.1	3.2	2.9
TCPL(2)	3.3	3.7	3.3	3.3
Union Carbide	3.5-4.5(3)	3.0-4.0	3.0-4.0	3.0-4.0
NEB	3.0	3.1	3.2	3.6

(1) Supplemental Forecast
(2) Real Domestic Product rather than Gross National Product.
(3) 1982-1985.

Table 4-2

POPULATION - CANADA
GROWTH RATES
Comparison of Forecasts
(Percent per Annum)

	1980-1985	1985-1990	1990-1995	1995-2000
Gulf	1.0	0.9	0.7	0.5
Norcen	1.0	1.0	0.9	0.9
NOVA	1.0	1.0	—	—
Petro-Canada	1.0	1.0	0.9	0.9
Shell	1.0	1.0	0.9	0.7
Texaco	1.1	0.9	0.8	0.8
NEB	1.0	1.0	0.9	0.9

Table 4-3

NUMBER OF HOUSEHOLDS - CANADA
GROWTH RATES
Comparison of Forecasts
(Percent per Annum)

	1980-1985	1985-1990	1990-1995	1995-2000
Gulf	2.0	1.3	0.9	0.7
Norcen	2.8	2.1	1.3	1.3
Petro-Canada	2.1	1.8	2.2	1.8
Shell	2.2	1.5	1.1	1.0
NEB	2.3	2.2	1.3	1.3

A number of Submittors were concerned about the effects on the economy of the NEP and the current impasse between the Federal Government and the Province of Alberta. Although no Submittor provided a detailed quantitative assessment of the macroeconomic impact of the NEP, most expected that the NEP would reduce energy-related investment activity and that this, in turn, would reduce the rates of economic growth from those forecast and submitted to the Board before the announcement of the NEP. Imperial expected that the NEP would reduce the level of Canadian economic activity from one to two percent in 1985 and 1990; whereas both Petro-Canada and TCPL thought that the NEP might increase economic growth by accelerating the development of Canada's energy-resource base.

Views of the Board

The Board's projections of the Canadian economy, including the population projections, were prepared using a version of the CANDIDE econometric model of the economy in conjunction with selected assumptions related to such factors as demography, labour force participation rates, the external trade environment, the exchange rate, and government fiscal and monetary policies.

The Board has prepared two economic forecasts: a base case and a high case. The base case was adopted for the Board's low and middle case demand forecasts, while the high case economic forecast was used to develop the intermediate and high case demand forecasts.

The Board's base case economic forecast is compared with Submittors' forecasts in Tables 4-1 to 4-3. It projects moderate rates of economic growth throughout the forecast period. The average growth rate of real GNP over this period is forecast to be 3.2 percent.

The annual rate of increase in population is predicted to slow from an average of 1.5 percent over the historical period 1960 to 1979, to 0.98 percent over the period 1980 to 2000. The forecast assumes that the fertility rate will remain constant at the replacement level of 2.1 children per female of child-bearing age throughout the forecast period. Net immigration is assumed to be 40 000 persons and 60 000 persons in 1981 and 1982 respectively. Thereafter, net immigration is assumed constant at 80 000 persons per year. The resultant population is forecast, in the base case, to be 29 million by the year 2000.

Other features characterising the projection of the economy in the base case and a discussion of the high case economic forecast are provided in Appendix C.

4.4 Energy Prices

Views of Submittors

Price is an important economic factor affecting the level of energy demand. Relative energy prices are the major determinant of competition between fuels. Most Submittors who presented demand forecasts also provided information on their underlying forecasts.

Those Submittors providing information on their energy price forecasts generally began with a discussion of the future course of world crude oil prices in comparison with general indices of overall inflation, that is, the real price of world crude oil. Significant differences of opinion were evident in this regard. NOVA expected free-on-board world crude prices to increase each year at the same rate as the Wholesale Price Index in the United States — a zero real price increase per annum. The majority of the Submittors providing this type of information projected real increases of two to three percent per annum in world crude prices. Gulf, however, forecast real increases of 3.5 to 4.0 percent per annum to 1989 and constant real prices thereafter. One Submittor, TCPL, attempted to account for periodic supply disruptions by assuming, in addition to a two percent per annum real increase, that real prices would increase by a further five percent every fifth year.

With respect to Canadian crude oil pricing, most forecasts of energy demand were prepared prior to the announcement of the NEP and as a result, price projections employed in these forecasts did not reflect the pricing provisions of the Program. Several Submittors, however, filed supplemental submissions after the announcement of the NEP and most of these provided qualitative information on the differences between the NEP pricing provisions and their own price forecasts. Several others prepared revised demand forecasts based on the pricing provisions of the NEP.

Canadian crude oil prices were most commonly referenced to world or United States prices. The majority of Submittors who provided information on their Canadian crude oil pricing forecasts believed that Canadian prices would reach 85 percent of the world, United States, or Chicago average price by 1985 or 1986. Shell expected domestic prices to reach only 75 percent of world prices by 1986; however, several Submittors thought that Canadian prices would reach a higher proportion of world prices. Nova Scotia, for example, expected that Canadian crude oil prices would reach world levels by 1986, and Imperial believed that domestic oil prices would increase to levels close to import replacement costs.

Submittors were generally in agreement that natural gas would be priced in existing markets at 85 percent of the thermal equivalent of crude oil at the Toronto refinery-gate. Some stated that this price relationship would exist prior to the application of the Syncrude levy to the price of crude oil, while others did not specify whether or not the levy was included in their forecasts. For new gas market regions, the expected price advantage of natural gas over crude oil ranged from 10 to 35 percent.

While the forecast rate of increase of electricity prices differed among Submittors, there was general concurrence that electricity prices would increase more slowly than oil and natural gas prices in Canada. While acknowledging that electricity could improve its competitive position in Ontario and Québec, Shell assumed in its forecasts that the present competitive position of electricity vis-à-vis natural gas and oil products would not change.

With respect to the pricing of coal, several Submittors expected it to remain the cheapest fossil fuel, and others thought that it would become more price competitive in heavy industrial use over the forecast period. Solar energy was forecast not to be competitive at least until the late 1980s by those Submittors who discussed this alternate energy form.

Views of the Board

One of the principal features distinguishing the Board's middle case forecast from its higher and lower demand cases is the set of price assumptions employed. For its middle case forecast, the Board based its oil and natural gas price forecast on the provisions contained in the NEP. For later years of the forecast period, Board judgement was exercised, since the NEP did not include a projection of oil and gas prices to the year 2000.

The forecast burner-tip prices of petroleum products are based on Toronto refinery-gate oil prices, to which are added the appropriate transportation differentials, and distribution and marketing margins. The Toronto refinery-gate crude oil price, in turn, is the sum of the well-head price of conventional oil, gathering and transportation charges, and the petroleum compensation charge which incorporates the Syncrude levy.

Consistent with historical experience, gathering charges, transportation charges, and distribution margins have been assumed to remain constant in real terms. The well-head price of conventional oil was forecast to rise at NEP designated rates until 1990, and to increase by $28.35 per cubic metre ($4.50 per barrel) every six months thereafter. The petroleum compensation charge, which is applied to crude oil at the refinery-gate and to imported petroleum products, was assumed, as in the NEP, to reach $63.32 per cubic metre ($10.05 per barrel) in 1983. It was assumed that this charge would increase by a further $18.90 per cubic metre ($3 per barrel) in 1984/85, and then remain at this level throughout the forecast period.

Burner-tip prices of natural gas are based on Toronto city-gate prices, to which the appropriate transportation and distribution margins are added. The Toronto city-gate price of gas, excluding the natural gas sales tax, is linked directly to the forecast well-head price of conventional oil in accordance with the NEP. This implies an increase of $.0053 per cubic metre in the Toronto city-gate price of gas for each $6.30 per cubic metre increase in the well-head price of oil ($.15 per thousand cubic feet for every $1 per barrel). To this price is added the natural gas sales tax, which under the NEP reaches $.026 per cubic metre in 1983 ($.75 per thousand cubic feet). The tax is assumed to remain at this level throughout the forecast period. As a result of these forecasts, the Toronto city-gate price of natural gas relative to the Toronto refinery-gate price of crude oil declines from approximately 80 percent in 1980 to 65 percent by 1984. After 1984, the price of gas relative to oil begins to increase, reaching 74 percent by 1990 and 80 percent in the year 2000.

The forecasts of electricity prices to 1984 are based on utility announcements and developed separately for each province. Expected rate increases vary significantly among the provinces, from a forecast increase in nominal terms of two percent per year in Manitoba to increases of 10 to 18 percent per year in the higher cost Atlantic provinces. After 1984, electricity prices in each province are assumed to remain constant in real terms.

For illustrative purposes, the Board's energy price forecasts are summarized for the Province of Ontario in Tables 4-4 and 4-5. The former Table provides information on the Board's projected burner-tip prices for the major energy forms in the residential, commercial and industrial sectors of Ontario. Table 4-5 provides detail on relative energy prices in each of these sectors of the province. It should be noted that burner-tip prices differ in each region of Canada because of differences in such factors as transportation and distribution margins, and electric utility rate schedules.

Table 4-4

NEB MIDDLE DEMAND CASE
FORECAST BURNER TIP ENERGY PRICES - ONTARIO
($/Gigajoule)

	Nominal Dollars						1980 Constant Dollars[1]					
	1980	1983	1985	1990	1995	2000	1980	1983	1985	1990	1995	2000
Crude Oil at Toronto Refinery Gate	2.95	5.48	7.36	13.08	20.48	28.00	2.95	4.08	4.77	6.01	6.77	6.83
Natural Gas at Toronto City Gate	2.31	3.65	4.83	9.67	15.99	22.39	2.31	2.72	3.13	4.44	5.29	5.46
Residential Sector												
Natural Gas	3.50	5.24	6.65	12.24	19.56	27.23	3.50	3.91	4.30	5.63	6.47	6.64
Light Fuel Oil	4.36	7.36	9.52	16.11	24.68	33.71	4.36	5.48	6.16	7.40	8.16	8.22
Electric Appliances	12.06	16.31	19.32	27.18	37.76	51.19	12.06	12.15	12.49	12.49	12.49	12.48
Electric Space Heating	7.79	10.53	12.48	17.55	24.38	33.05	7.79	7.85	8.07	8.07	8.06	8.06
Commercial Sector												
Natural Gas	2.80	4.30	5.57	10.72	17.45	24.37	2.80	3.20	3.60	4.93	5.77	5.94
Light Fuel Oil	4.10	7.01	9.11	15.54	23.88	32.62	4.10	5.22	5.89	7.14	7.90	7.95
Electricity	8.56	11.58	13.72	19.29	26.80	36.34	8.56	8.63	8.87	8.87	8.86	8.86
Industrial Sector												
Natural Gas	2.50	3.90	5.11	10.08	16.55	23.15	2.50	2.91	3.30	4.63	5.48	5.64
Heavy Fuel Oil	2.49	4.74	6.43	11.56	18.19	24.89	2.49	3.53	4.15	5.31	6.02	6.07
Electricity	6.62	8.95	10.60	14.90	20.71	28.07	6.62	6.67	6.85	6.85	6.85	6.84

[1] Deflator: CPI

TABLE 4-5

NEB MIDDLE DEMAND CASE
FORECAST RELATIVE ENERGY PRICES - ONTARIO[1]

	1980	1985	1990	1995	2000
Residential					
Gas/Oil	0.695	0.621	0.692	0.740	0.772
Gas/Electricity space heating	0.592	0.692	0.894	1.016	1.030
Oil/Electricity space heating	0.851	1.119	1.297	1.377	1.333
Commercial					
Gas/LFO	0.717	0.643	0.726	0.768	0.785
Gas/HFO	1.105	0.868	0.933	0.967	0.988
Gas/Electricity	0.419	0.521	0.713	0.835	0.860
LFO/Electricity	0.584	0.810	0.982	1.087	1.095
Industrial					
Gas/Oil	1.026	0.814	0.892	0.931	0.952
Gas/Electricity	0.445	0.568	0.795	0.940	0.970
Oil/Electricity	0.433	0.697	0.892	1.010	1.019

[1] Price ratios after adjustment for efficiency differences.

CHAPTER 5
PRIMARY ENERGY DEMAND

5.1 Introduction

The primary energy demand forecasts are examined in this chapter. The Board has prepared four demand cases: low, middle, intermediate and high. Section 5.2 discusses middle case primary energy demand by energy form, while in Section 5.3, the low, intermediate, and high demand cases are examined. Submitted information did not always follow exactly the definitions specified in the Outline for Submissions; this information had to be put on a basis comparable with other submissions. In addition, some of the forecasts preceeded whereas others followed the announcement of the NEP. This affected the Board's ability to compare the Submittors' oil products demand more than it did total primary energy demand.

The basic difference between primary energy and the other common measure, secondary energy, is that primary energy includes intermediate uses of energy, such as fossil fuels used to produce electricity, while secondary energy excludes such intermediate uses, focusing only on end-use by the energy consumer.

Primary energy demand includes:

–energy use in the residential, commercial, industrial, and transportation sectors;

–non-energy use of hydrocarbons (such as petrochemical feedstocks, lubricants, and asphalt);

–energy use in the energy supply industries (such as natural gas pipeline fuel);

–conversion losses in the transformation of energy forms (such as fossil fuels used to produce electricity);

–electricity from nuclear and hydro sources assessed at the fossil fuel equivalent of 10.5 megajoules/kilowatt hour.

5.2 Primary Energy Demand by Fuel Type

Views of Submittors

Information on Canadian primary energy demand by fuel type was provided by seven of the Submittors, and a summary of their forecasts is provided, along with the Board's forecast, in Table 5-1. The average annual percentage increases implied by these forecasts are compared in Table 5-2 for the period 1980 to 2000 using five-year sub-periods. Details of these forecasts by energy form are shown in Appendix F.

The Submittors' forecasts of primary energy demand for 1980, Statistics Canada's data yet being available, ranged from a low of 9 338 petajoules by Norcen to a high of 10 240 petajoules by Imperial. To a large extent, differences in forecasts for 1980 stemmed from the use of varying estimates of hog fuel, pulping liquor, and other renewable energy forms, which are difficult to measure.

Table 5-1

PRIMARY ENERGY DEMAND - CANADA
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000
Gulf(1)	9 981	11 450	13 127	14 894	16 704
Imperial	10 240	11 395	12 554	13 675	15 013
Norcen(1)	9 338	10 209	11 111	12 194	13 525
NOVA	9 700	10 715	11 889	13 147	14 782
Petro-Canada(1)	9 455	10 617	11 918	13 521	15 385
Shell(1)	9 956	10 964	11 840	—	13 505
Texaco	10 117	11 234	12 614	13 989	15 904
NEB	10 356	11 787	12 859	14 089	16 176

(1) Supplemental Forecast

Table 5-2

PRIMARY ENERGY DEMAND GROWTH RATES - CANADA
Comparison of Forecasts
(Percent per Annum)

	1980-1985	1985-1990	1990-1995	1995-2000	1980-2000
Gulf(1)	2.8	2.8	2.6	2.3	2.6
Imperial	2.2	2.0	1.7	1.9	1.9
Norcen	1.8	1.7	1.9	2.1	1.9
NOVA	2.0	2.1	2.0	2.4	2.1
Petro-Canada(1)	2.3	2.3	2.6	2.6	2.5
Shell(1)	1.9	1.5	—	—	1.5
Texaco	2.1	2.3	2.1	2.6	2.3
NEB	2.6	1.8	1.8	2.8	2.3

(1) Supplemental Forecast

By the year 2000, estimates of primary energy demand ranged from 13 505 petajoules by Shell to 16 704 petajoules by Gulf, representing a divergence from the highest to the lowest forecast of less than twenty percent.

The Submittors' estimates of the total increase in primary energy demand over the entire twenty-year forecast period fell in the range of 36 to 67 percent. With respect to average annual percentage growth rates in primary energy demand over the twenty-year forecast period, the lowest estimate was provided by Shell, 1.5 percent per annum, while Gulf expected the most rapid growth in energy demand, 2.6 percent per annum.

Most Submittors expected the rate of growth in primary energy demand to slow until 1990 or 1995, but to increase thereafter. The expected patterns of economic growth and real energy price increases were the principal reasons for this forecast pattern of primary energy demand growth. Gulf, however, expected the rate of growth in energy demand to decline throughout the forecast period.

Primary demand for oil was expected to experience the slowest growth compared with the demand for all the energy forms. Indeed, several Submittors expected no growth or even a decline in the demand for crude oil over the twenty-year forecast horizon. Estimates ranged from a decline of 0.4 percent per annum by Norcen to an annual increase of 0.5 percent by Dome. Overall conservation efforts and the rapid rise in oil prices relative to other energy forms were cited as the major reasons for the slower growth in oil product demand.

Electricity demand can be met by generation from hydroelectric and nuclear sources and from fossil fuels. The use of hydraulic sources for electricity generation was projected to grow at an average annual rate of between 1.5 and 3.3 percent. Submittors expected the use of nuclear fuels for electricity generation to grow more rapidly. Estimates ranged from 5.1 to 7.3 percent per annum, on average, over the forecast horizon, although much of this growth was expected later in the period.

Estimates of the growth in coal demand varied significantly, from 1.8 percent per annum by Shell to 5.8 percent by the Coal Assn. The difference between these two estimates was evident with respect to slower coal demand growth in both the industrial and electrical generation sectors in the Shell forecast compared with the estimates provided by the Coal Assn.

Demand for natural gas was forecast to grow in the range of 2.1 to 3.2 percent per annum. Hog fuel, pulping liquor, and other renewables were expected to increase on average in the range of 3.0 to 4.9 percent per year.

Overall, the pattern of primary energy demand growth projected by Submittors suggested that electricity generated from hydro and nuclear sources would replace oil as the main energy form in Canada by the 1990s. All Submittors expected oil to lose market share and only one considered that it would still be the most important form of primary energy by the end of the century.

A comparison of Canadian primary energy demand forecasts by fuel type is presented in Table 5-3 for the year 1990, showing the Board's middle case forecast as compared to the highest and the lowest submitted forecasts.

Table 5-3

PRIMARY ENERGY DEMAND IN 1990 - CANADA
Comparison of Forecasts
(Petajoules)

	NEB MIDDLE CASE	SUBMITTORS HIGH[4]	LOW[4]
Natural Gas[1]	2 799	2 969	2 310
Crude Oil[2]	3 691	3 955	3 142
LPG[3]	160	273	157
Hog Fuel & Pulping Liquor	448	484	277
Other Renewables	87	116	20
Coal	1 336	1 709	1 083
Hydro	3 356	3 185	2 847
Nuclear	982	1 088	749
Total Primary Energy	12 859	13 127	11 111

(1) Includes ethane
(2) Excludes refinery LPG
(3) Includes both gas plant and refinery LPG
(4) The high and low forecasts may represent different Submittors for each energy form; total primary energy is therefore not the sum of the individual energy forms.

Views of the Board

The Board's middle case primary energy demand forecast is summarized in Table 5-4 and Figures 5-1 and 5-2. Canadian primary energy demand is expected to increase from 10 356 petajoules in 1980 to 16 176 petajoules by the year 2000. This represents an overall increase of 56 percent and an average annual growth rate of 2.3 percent over the forecast period. The rate of growth of primary energy demand is expected to slow throughout the current decade in response to rapid price increases, but to pick up in the 1990s as real price increases slow, the potential for further conservation efforts diminishes, and economic growth accelerates.

Primary oil demand is forecast to grow only 0.2 percent per annum, considerably more slowly than overall primary energy demand, principally because of the expected increase in oil prices compared with the prices of other fuels. These relative price increases are largely expected to occur during the current decade and, as a result, primary oil demand is expected to actually decline until 1990. The share of total primary energy supplied by oil is forecast to decline from 39.3 percent in 1980 to 26.3 percent by the year 2000.

As shown in Figure 5-1, all other energy forms are expected to become relatively more important sources of primary energy. Nuclear and hydro sources, used for electricity generation, are forecast to represent 33 percent of total primary energy require-

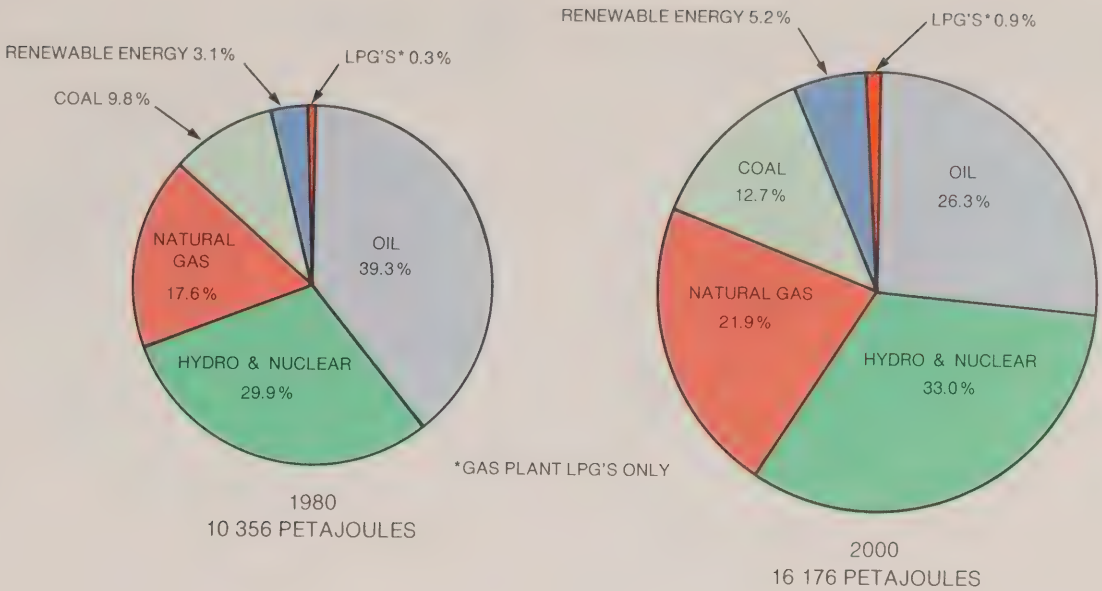

Figure 5-1 Primary Energy Demand - Canada NEB Forecast

ments in the year 2000, compared with 29.9 percent in 1980. The proportion for natural gas is expected to be 21.9 percent in 2000 compared with 17.6 percent in 1980. Coal, renewable energy and liquefied petroleum gases are also expected to supply increasing proportions of Canada's total primary energy requirements. Renewables are expected to grow the fastest, although starting from a very low base in 1980, and will represent only 5.2 percent of total primary energy demand by the year 2000.

The primary energy equivalent of all the resources used for electricity generation is shown in Figure 5-2. The Figure shows that by the year 2000, 44.2 percent of primary energy is forecast to be devoted to the generation of electricity as compared with 38.7 percent in 1980.

The Board's current forecast of total primary energy demand is somewhat lower in the later years of the forecast period than the forecast prepared for the November 1979 Reasons For Decision; by the year 2000 the present forecast is seven percent lower than the earlier forecast. Again, the role of energy prices is important in explaining this difference. The 1979 forecast assumed that world crude oil prices would remain at the 1979 level in real terms and that Canadian crude oil prices would reach world levels by 1983. This implied that Canadian oil and gas prices would remain constant in real terms after 1983, while in the current forecast real oil and gas prices are expected to increase. Much of the difference between the two forecasts is reflected in the current forecast's lower primary oil demand

5.3 Low, Intermediate and High Demand Cases

To account for some of the uncertainties associated with long-term energy demand forecasting, and to demonstrate the sensitivity of the demand forecast to changes in underlying factors, the Board has adopted the approach of estimating ranges rather than relying on point forecasts. The major uncertainties, among those which can to some extent be measured, are the pace of energy price increases and the overall performance of the economy. In addition to its middle case, in which energy price assumptions are based on NEP pricing provisions, the Board has adopted a lower demand case, plus two higher demand cases that are termed intermediate demand and high demand.

The low demand case illustrates the sensitivity of the demand forecast to higher energy prices, other things being equal. It is based on the same forecast of economic activity as the middle case, but energy prices are increased by 30 percent, in real terms, above the prices forecast in the middle case, with the increase in prices phased in over the five year period, 1981-1985.

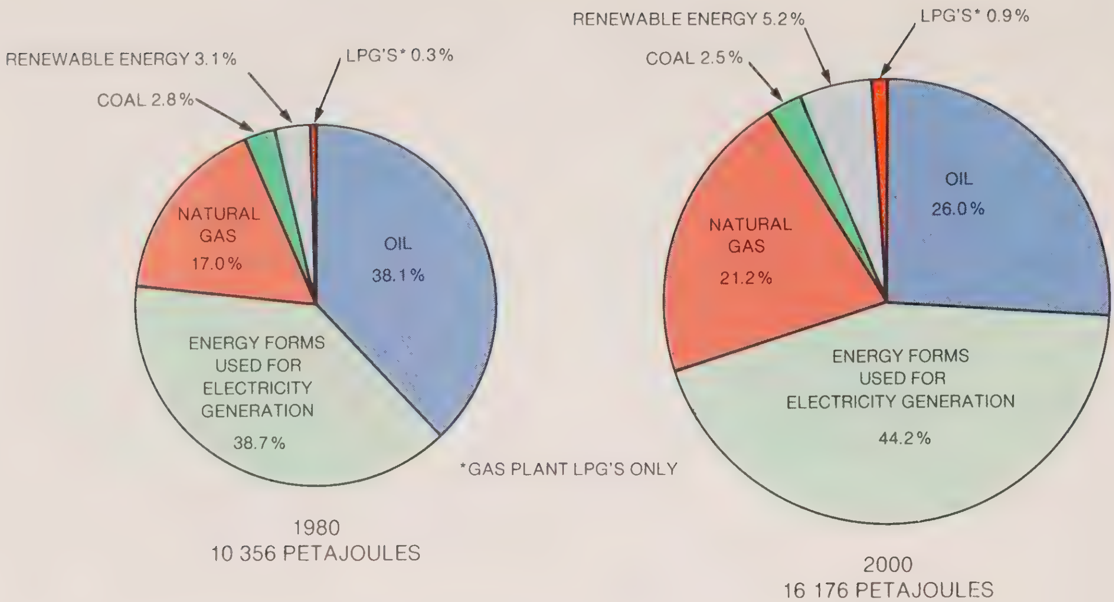

Figure 5-2 Primary Energy Demand - Canada
NEB Forecast - Showing Total Role of Electricity

Table 5-4

NEB FORECAST OF PRIMARY ENERGY DEMAND - CANADA
(Petajoules)

NEB	1980	1985	1990	1995	2000	AAI-% 1980-2000
Natural Gas[1]	1 819.7	2 424.8	2 799.4	3 089.6	3 545.4	3.4
Crude Oil[2]	4 068.3	3 893.9	3 757.3	3 904.1	4 251.2	0.2
LPG[3]	28.5	38.8	93.3	141.1	149.6	8.6
Hog Fuel & Pulping Liquor	317.9	380.6	447.9	506.7	568.4	2.9
Other Renewables	7.6	9.5	87.4	164.3	266.6	19.5
Coal	1 017.8	1 144.0	1 335.5	1 710.9	2 051.4	3.6
Hydro	2 660.2	3 044.2	3 355.7	3 514.5	3 927.2	2.0
Nuclear	436.1	851.9	982.0	1 058.1	1 415.7	6.1
Total Primary Energy	10 356.1	11 786.7	12 858.6	14 089.3	16 175.6	2.3

(1) Includes ethane
(2) Includes refinery LPG
(3) Includes gas plant LPG only
AAI—Average Annual Increase

The intermediate demand case shows the variance in energy demand resulting from a forecast of higher economic growth than in the middle case. The average annual increase in real GNP is 4.0 percent as opposed to 3.2 percent. Energy prices are the same as in the middle case.

The high demand case illustrates the sensitivity of energy demand to both higher economic activity and lower energy prices. It is based on the same forecast of higher economic growth as adopted for the intermediate demand case, but with energy prices that are 30 percent lower in real terms than in the middle and intermediate cases, with the price reduction phased in over the five-year period, 1981-1985.

The demand cases and the assumed changes in the underlying price and economic forecasts are summarized below:

Demand Case	Economic Activity Case	Energy Price Forecast
High	High (4 percent per year average growth in real GNP)	NEP less 30 percent phased in over 5 years
Intermediate	" " "	NEP
Middle	Base (3.2 percent per year average growth in real GNP)	NEP
Low	" " "	NEP plus 30 percent phased in over 5 years

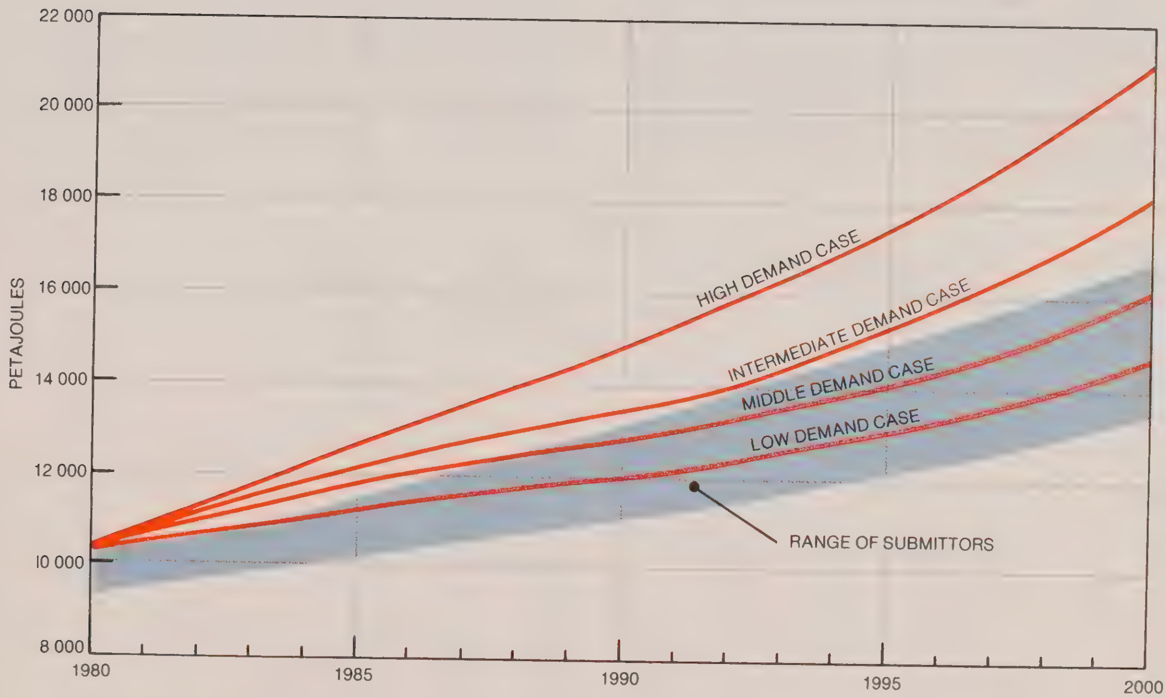

Figure 5-3 Range of Primary Energy Demand - Canada
NEB Cases and Submittors' High and Low

Energy price assumptions used for the alternative cases involve higher or lower energy prices in total, and do not involve changes in the relative prices of competing fuels. There are potentially a number of other alternative cases, equally probable with those employed in the present forecast, in which the price of one fuel changes in comparison with another. For example, it is possible that natural gas prices relative to crude oil prices could fall even further than has been assumed in this forecast. In such an event, it is evident that natural gas demand would rise at the expense of oil product demand. While the directional effects of such relative price shifts are fairly evident, no attempt was made to further expand the range of alternative cases in this manner.

The Board's projections of total primary energy demand for the low, intermediate, and high demand cases are compared with its middle case forecast in Table 5-5 and Figure 5-3. By the year 2000, the low demand forecast is 9.3 percent lower than the middle case forecast, reflecting the sensitivity of the forecast to the assumption of 30 percent higher energy prices. The high demand forecast is 30 percent higher than the middle case by the year 2000, reflecting the effects of both more rapid economic growth and 30 percent lower energy prices. By the year 2000, the intermediate demand case is 12.4 percent higher than the middle case forecast, reflecting the effects only of more rapid economic growth.

As one would expect, estimates of primary oil demand are different for the various alternative demand cases. Forecasts of primary oil demand are 3 965, 4 251, and 5 302 petajoules by the year 2000 in the low, middle, and high demand cases respectively. This represents a range of 25 percent from the highest to the lowest forecast.

Table 5-5

PRIMARY ENERGY DEMAND - CANADA
NEB Cases
(Petajoules)

	1980	1985	1990	1995	2000
Low Demand	10 356	11 249	12 040	13 025	14 679
Middle Demand	10 356	11 787	12 859	14 089	16 176
Intermediate Demand	10 356	12 127	13 441	15 345	18 178
High Demand	10 356	12 596	14 798	17 500	21 078

CHAPTER 6
DEMAND FOR ENERGY BY SECTOR — MIDDLE DEMAND CASE

6.1 Introduction

In this chapter, the Board's middle case forecast of energy demand is discussed for each market sector in total, by individual fuels, and is compared with the forecasts of the Submittors.

Some Submittors, namely, Gulf, Imperial, Petro-Canada, Shell and Texaco, provided forecasts of energy demand by market sector and by energy type, for each region of the country. These forecasts are compared with the Board's forecast at a total Canada level. Many other Submittors, however, restricted their forecasts to individual regions, specific sectors or particular energy forms. Although much of the discussion in the ensuing sections of this chapter relates to the demand forecasts at a national level, the Board emphasizes that all evidence presented, whether related to energy demand at a national level or to a specific region, sector, or fuel, was taken into account in preparing its estimates of total energy demand.

Appendix G of this report presents a comparison of the forecasts of total energy demand in each sector, by province.

With regard to demand at a total Canada level, Table 6-1 presents a comparison of the Board's forecast of energy demand by sector with the high and low estimates of the Submittors for 1980, 1990 and 2000. For each of these years, the highest and lowest projected demand in each sector is given but these demands may not necessarily be the forecasts of the same Submittor for each sector or for each year shown.

It should be noted that Submittors have not always used the same definitions of particular sectors. Wherever possible, an attempt was made to identify the differences and to account for them. Partly as a result of these differences, and partly as a result of other factors, the estimates for 1980 were at times quite divergent. Differences in estimates for 1980 would affect the projected levels of demand in later years. For these reasons, the relative growth rates in the individual forecasts of the Submittors are also compared.

6.2 Demand in the Residential Sector

Views of Submittors

In the residential sector, energy is required for space heating, water heating, appliance operation, and lighting. Space heating is the most significant residential use of energy, followed by water heating.

Most Submittors anticipated only moderate increases in energy use in this sector. Petro-Canada and Texaco projected the strongest rate of growth, at 1.5 percent per year between 1980 and 2000. Other Submittors expected nearly unchanged residential energy demand during the forecast period. The forecasts of the Submittors are summarized in Table 6-2.

Submittors' energy demand projections reflected their views on growth rates of Canada's households and real incomes; the size

Table 6-1

TOTAL ENERGY DEMAND BY SECTOR - CANADA
Comparison of Forecasts
(Petajoules)

	1980			1990			2000			AAI-% 1980-2000		
	NEB	Submittors		NEB	Submittors		NEB	Submittors		NEB	Submittors	
		High	Low		High	Low		High	Low		High[2]	Low[2]
Residential	1 244	1 374	1 126	1 297	1 480	1 083	1 451	1 814	1 135	0.8	1.5	0.0
Commercial	905	955	730	1 049	1 123	857	1 393	1 655	947	2.2	3.4	1.3
Petrochemical	389	439	224	762	730	476	985	901	542	4.8	6.4	2.3
Industrial[1]	2 326	2 505	1 927	2 888	3 318	2 530	3 833	4 317	3 065	2.5	3.2	2.3
Transportation	1 957	2 070	1 835	2 121	2 195	1 816	2 385	2 555	1 900	1.0	1.4	0.1
Road	1 564	1 670	1 355	1 632	1 727	1 239	1 748	1 908	1 358	0.6	0.9	–0.4
Rail	107	122	95	126	148	103	152	186	110	1.8	3.0	0.5
Air	175	184	158	235	263	149	332	359	176	3.3	3.6	0.4
Marine	112	117	100	128	131	119	153	166	126	1.6	2.6	0.4
Other Non-Energy Use	259	265	187	336	369	268	438	466	333	2.7	3.0	1.3
Own Use and Losses	493	712	479	545	1 056	480	648	1 152	530	1.4	2.4	0.3

(1) Including hog fuel and pulping liquor, and coke and coke oven gas, but excluding petrochemicals.
(2) Based on the highest or lowest growth projected by individual Submittors.
AAI - Average Annual Increase.

Table 6-2

TOTAL ENERGY DEMAND IN THE RESIDENTIAL SECTOR- CANADA
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000	AAI-% 1980-2000
Gulf(1)	1 126	1 067	1 083	1 108	1 135	0.0
Imperial	1 374	1 378	1 371	1 369	1 403	0.1
Petro-Canada(1)	1 322	1 385	1 456	1 610	1 793	1.5
Shell(1)	1 318	1 366	1 377	—	1 384	0.2
Texaco	1 344	1 387	1 480	1 617	1 814	1.5
NEB	1 244	1 274	1 297	1 363	1 451	0.8

(1) Supplemental Forecast
AAI - Average Annual Increase

and composition of Canada's housing stock and expected insulation standards for new and existing houses; anticipated improvements in the efficiency of furnaces; the stock and efficiency of appliances; future energy prices and interfuel competition; and non-price determinants of fuel choice such as conversion assistance, insulation assistance, direct assistance to transporters, distributors and others, as well as the perceived security of supply of different fuels. Each of these areas is discussed in this section.

Total residential energy demand depends generally on the number of households, since space and water heating are the major uses of energy in this sector, and on real disposable incomes, as income levels determine the size and type of housing units and appliance ownership rates.

Forecasted annual growth rates for the number of households ranged from a low of 1.3 percent per year predicted by Gulf to a high of 2.0 percent per year predicted by Petro-Canada.

Submittors' views on the composition of the housing stock were basic to their forecasts since apartments and other multiple housing units use less energy than single houses. Some Submittors expected increased demand for single family detached housing units as the population ages. Others predicted that the percentage of single family detached dwellings in the housing stock would decrease, citing expected higher energy and other costs of home ownership and operation.

Submittors generally stated that as energy prices have risen, additional insulation has become worthwhile in existing and in new housing units and that future residential energy demand will depend to a considerable extent on the standards to which houses will be insulated. Petro-Canada and Norcen used a price-driven forecasting methodology, and did not estimate the specific energy savings from additional insulation, although both expected energy demand per household to decrease over the forecast period. Several other Submittors provided separate estimates of likely energy savings from upgraded insulation in existing and in new housing units. Some, for example the Province of British Columbia, also provided details of energy savings by type of housing unit.

For new housing units, estimated energy savings by the year 2000 from upgraded insulation ranged from ten percent, predicted by ICG and its subsidiary companies, to 75 percent, predicted by TCPL. TCPL estimated that the adoption of a new building code would save 30 percent of 1980 heating requirements. By 1990 single houses built according to the insulation standards of the Canadian Electrical Association were expected to require half the heating energy of houses built in 1980.

Other Submittors predicted that heating requirements of new houses would be reduced by 10 to 30 percent from the requirements of houses built in the late 1970s. However, according to the Province of Ontario, additional reductions could be achieved by triple glazing of windows and through passive solar design features.

Lesser space heating energy savings were forecast by most Submittors for new multiple housing units, although savings of 30 percent were thought possible by TCPL.

Submittors were not in agreement on the likely heating energy savings from reinsulation of existing houses. According to NC Gas, at energy prices of September 1980, upgrading of storm doors and windows, weatherstripping, and attic insulation, but not wall insulation, were financially attractive in existing single family houses. However, Submittors differed in their estimates of the number of houses that would be reinsulated, and the standards to which such houses would be reinsulated. For example, TCPL expected that only 20 percent of existing houses would be reinsulated by the year 2000. Imperial anticipated that potential heating energy savings of 30 percent from retrofitting would be realized by the end of the forecast period. Other Submittors estimated heat energy savings ranging from 8 to 25 percent.

Most Submittors expected little saving from reinsulation of existing multiple unit buildings, in part because of limited potential for retrofitting, and in part because of the separation between ownership and occupancy.

Submittors differed in their assessment of energy savings from improved furnace efficiencies. Many Submittors predicted efficiency gains of about 10 percent by the year 2000, compared to 1979 or 1980 efficiencies. However, Imperial estimated that new furnaces would be 30 percent more efficient than older furnaces. Some Submittors had assumed that existing oil or gas furnaces are only 65 percent efficient.

Ontario Hydro noted the expected high capital costs of heat pumps and of high efficiency gas furnaces, and Union Gas assumed no change in furnace efficiencies to the year 2000, in part because capital costs of the new gas furnaces were not known.

Ontario Hydro submitted two studies on the performance of heat pumps. One dealt with new houses fitted with heat pumps and using electric resistance heating as the supplementary heat source. The other was on heat pumps added to existing homes

using oil, gas, or electric resistance heating as the supplementary source. The studies concluded that heat pumps substantially reduce consumption of energy to provide heat, but that improvements in design, reliability and serviceability are still required.

Several Submittors stated that Canadian households are near saturation levels with regard to the use of electric appliances. However, Petro-Canada suggested the contrary.

Submittors expected improved operating efficiencies. For example, Imperial anticipated a 15 percent improvement, while Shell expected energy savings in water heating, from improved burner efficiency, thicker tank insulation, and reduced hot water temperatures.

Prior to the announcement of the NEP, many Submittors predicted that prices of oil and natural gas would increase in excess of the rate of inflation, and that electricity prices would rise at about the rate of inflation. Several Submittors, for example Imperial, Petro-Canada, and ICG had anticipated a reduced ratio of gas to oil prices in expansion markets, and conversion cost assistance, to encourage furnace conversions from oil to natural gas. Most Submittors predicted that natural gas would be cheaper than oil or electricity for spaceheating in the early part of the forecast period, but that electricity would become relatively cheaper towards the latter part of the forecast period.

TCPL stated that the choice of fuel for space heating depends on life cycle costs of heating systems, considering both burner-tip prices of different fuels and equipment costs.

Most agreed that, where available, new single family houses would be heated predominately by natural gas. However, CPA expected that electricity's share of the residential sector would increase because of its improved competitive position, and that the share of natural gas would increase slightly, because of expansion of the gas service area in Eastern Canada. Submittors expected that multiple unit housing would be heated by electricity and natural gas, with the market share of gas being smaller in multiple units than in single family housing.

Submittors pointed out that for existing houses, choice of fuel for space heating may be limited by the cost of converting from the existing heating system. NBEPC indicated that conversions from oil to natural gas are relatively inexpensive, that conversions from oil or natural gas to electricity tend to be more expensive, and finally, that conversions to natural gas from electricity in houses with baseboard heaters, were unlikely.

Submittors expected that most houses converting from oil would be converting to natural gas. The Province of British Columbia stated that natural gas would always be the cheapest space heating fuel in British Columbia. Ontario Hydro doubted that electricity would account for a significant part of the oil conversion market.

Although some oil-fired water heaters are still in use, Submittors predicted their conversion to natural gas or electricity at the time of conversion of the space heating system.

Several Submittors expected that solar energy for space or water heating would become competitive by about 1990.

Submittors' forecasts of demand for the different fuels are shown in Table 6-3.

Submittors expected that several measures in the NEP would affect the use of energy in the residential sector. Submittors mentioned the furnace conversion grants, extension of gas service areas, and the extension of the Canadian Home Insulation Program.

Some Submittors, for example NOVA, Petro-Canada, Gulf, Union Gas and TQM, felt that, given expected fuel prices, the furnace conversion grants would succeed in inducing conversion of furnaces from oil. Gulf reduced its estimate of the average life of oil furnaces to only ten years as a consequence of the NEP.

Other Submittors, in particular Inland, IPAC, and ICG, noted that the pace of conversions from oil had increased prior to the announcement of the NEP. Several gas distributors had in operation burner rental programs to assist homeowners with conversion costs. Inland, together with furnace dealers, provided grants to alleviate the cost of converting to gas furnaces. These Submittors questioned the effectiveness of the NEP conversion grants in the light of the possibility that they may simply replace the distributors' programs.

Finally, some Submittors, including Imperial, stated that, in making their pre-NEP estimates, they had assumed the NEP type of assistance to convert oil furnaces, and had also assumed a reduced ratio of gas to oil prices in expansion markets.

Many Submittors, including Petro-Canada and TCPL, had anticipated extension of the gas service area to the Maritimes and Vancouver Island prior to the NEP. However, the Province of New Brunswick expressed concern relating to long term natural gas prices.

NC Gas stated that the NEP might induce conversions to natural gas, apart from the stimulus provided by the furnace conversion grants and market development bonuses. According to NC Gas, the NEP can be interpreted as a government commitment that natural gas will be cheaper than oil, and that natural gas is perceived to be in secure supply. Further, NC Gas felt that as the number of houses heated by gas increased, there would be less concern about its safety.

Canadian Solar Industries Association Inc. (CSIA) stated that since the NEP keeps costs of conventional energy low, use of solar energy would be discouraged.

Views of the Board

The Board estimates that total residential energy demand will increase from 1 244 petajoules in 1980 to 1 451 petajoules in the year 2000, or by 0.8 percent per year. The Board's forecast is compared to the Submittors' forecasts in Table 6-2 and Figure 6-1.

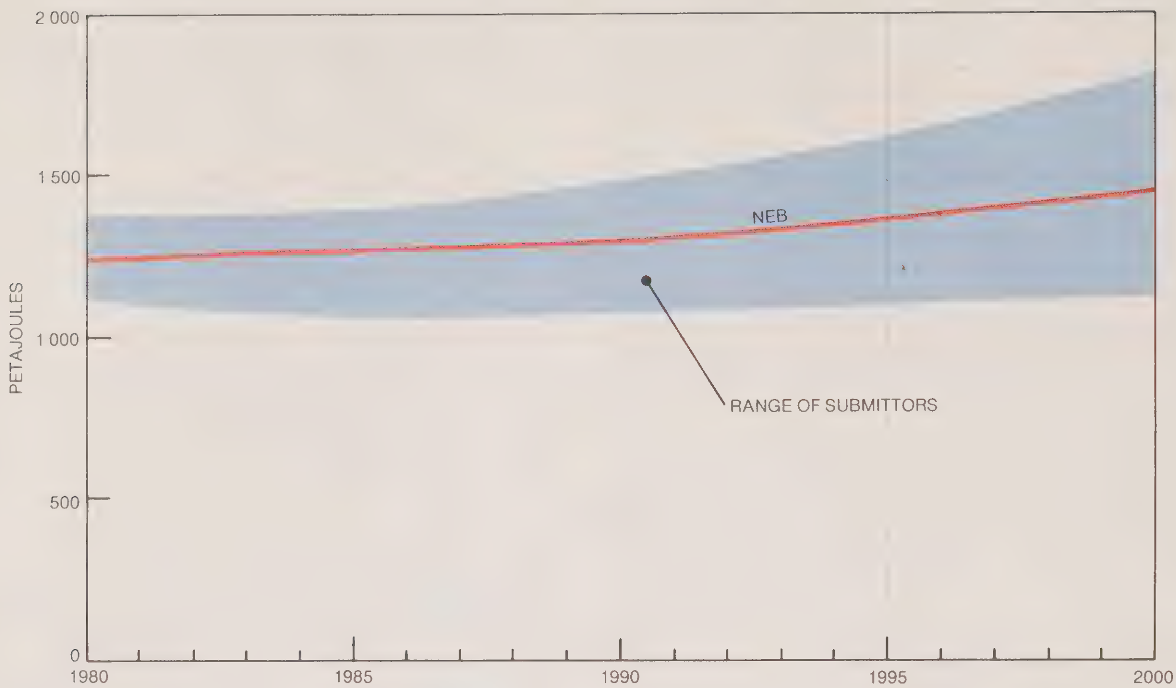

Figure 6-1 Energy Demand in the Residential Sector
Comparison of Forecasts

The Board forecasts total residential energy demand by considering the effects of expected changes over time in the number of households, real disposable income, the housing stock, energy prices, furnace efficiencies, and government policies.

Between the year 1980 and 2000 the Board forecasts the number of households to increase from 7.8 to 11.1 million, and real disposable income per household, measured in 1980 dollars, to increase from $24 400 to $28 800. Further, the Board assumes the ratio of single (detached and attached) to multiple housing units to decrease slightly over the forecast period, from 67 percent in 1980 to 65 percent by the year 2000.

Higher real incomes are expected to lead to increased energy demand per household, whereas higher energy prices, improved furnace technology, and the trend towards multiple unit housing are expected to reduce energy demand per household. On balance, the Board expects that average energy demand per household will decrease by 17.8 percent, from 159 gigajoules in 1980 to 131 gigajoules in the year 2000. Most of the reduction is expected to occur in the 1980s, in response to rapidly increasing real energy prices.

The Board forecasts residential sector demand for individual fuels by considering total sector demand, the extent of the natural gas service area, and the prices of the different fuels adjusted for fuel efficiency. Since space heating constitutes the largest use of energy in this sector, capital costs of heating systems for the different fuels are also considered.

The Board expects that the average efficiency of natural gas furnaces will reach 80 percent by the year 2000. While new gas furnaces, with efficiencies in excess of 90 percent, will be available in quantity by 1982 or 1983, the Board anticipates limited sales of these furnaces because of their cost. The new furnaces are expected to cost approximately twice as much as conventional gas furnaces. Where gas is available, conversion from oil to a conventional gas furnace frequently is worthwhile, even if the oil furnace is in good condition, given the annual fuel cost savings and the NEP oil furnace conversion grants. However, replacement of an oil furnace or of a conventional gas furnace with a high cost, high efficiency gas furnace does not appear obviously economical.

The average seasonal efficiency of oil furnaces is expected to approach 80 percent by the year 2000, from 65 percent in 1980, as older furnaces are replaced with more efficient new furnaces.

Use of electricity for space heating is forecast to increase, since, on an efficiency adjusted basis, electricity is expected to become cheaper than oil, and more competitive with natural gas than at present. Further, the Board is of the opinion that heat pumps can make a moderate contribution to residential space heating requirements by 2000. Heat pumps may be used in regions with moderate winter temperatures, or where both winter heating and summer cooling are required. Their level of market penetration will be influenced by alternative fuel costs. The Board has estimated increased use of electricity for space heating, as shown in Table 6-3.

The Board expects increased use of renewable energy, principally wood and solar, from the levels of the 1960s and most of the 1970s. The estimate of renewable energy shown for 1980 reflects increased use of wood for space heating in the Atlantic Region. Commencing in 1985, solar energy is expected to find measurable application for space and water heating.

In response to changes in relative fuel prices, the Board expects increased importance of gas, electricity, and renewable energy, and decreased use of light fuel oil. Residential use of coal is not expected to increase.

A combined share of natural gas, electricity, and renewable energy of approximately 80 percent is forecast for the year 2000, compared to a share of less than 60 percent in 1980. During the forecast period the share of light fuel oil and kerosene is expected to decrease from 33 percent to less than 9 percent. Diesel fuel, LPG and coal will account for the remaining 11 percent in the year 2000. The Board's forecast of residential sector fuel shares compared to fuel shares forecast by Submittors is shown in Table 6-4.

The Board's residential demand forecast reflects those specific provisions of the NEP that affect residential energy demand. These are: the extension of the natural gas service area; the oil furnace conversion grants; and the extension of the Canadian Home Insulation Program.

The Board forecasts that the light and heavy fuel oil share in the residential sector will decrease to about 16 percent by the year 1990. In making its forecast, the Board has considered several factors. The Board anticipates that a significant portion of households in Central and Eastern Canada will not have access to natural gas. Continued use of fuel oil is expected in these areas. Further, the NEP oil furnace conversion grants are payable only once per residence, on conversion from oil. Any further conversion, for example from a conventional gas furnace to a high efficiency gas furnace or to electricity will not be eligible for additional conversion assistance. Thus homeowners wishing to convert from oil may wait until the high efficiency gas furnaces become more widely available or until they are more confident about future prices of electricity and natural gas. All these factors may postpone realization of the NEP off-oil target of ten percent for light and heavy fuel oil.

Table 6-3

DEMAND IN THE RESIDENTIAL SECTOR BY ENERGY FORM - CANADA
Comparison of Forecasts
(Petajoules)

Energy Form	1980			1990			2000		
	NEB	Submittors		NEB	Submittors		NEB	Submittors	
		High	Low		High	Low		High	Low
Natural Gas	376	481	363	505	657	433	556	749	480
Oil									
LFO & Kerosene	411	468	405	200	387	195	126	263	101
Diesel Fuel	60	70	70	82	95	94	108	133	131
HFO	17	32	13	6	20	—	—	14	—
LPG	54	53	35	57	49	35	63	54	36
Other Renewables	3	8	—	13	51	5	35	106	35
Coal	5	5	3	4	6	2	4	7	—
Electricity	319	389	296	430	518	402	559	642	476
TOTAL[1]	1 244	1 374	1 126	1 297	1 480	1 083	1 451	1 814	1 135

[1] Not necessarily the sum of above energy forms as the high and low demand for particular energy forms often represent different Submittors.

Table 6-4

DEMAND IN THE RESIDENTIAL SECTOR BY ENERGY FORM - CANADA
MARKET SHARES
Comparison of Forecasts
(Percent)

Energy Form	1980			1990			2000		
	NEB	Submittors[1]		NEB	Submittors[1]		NEB	Submittors[1]	
		High	Low		High	Low		High	Low
Natural Gas	30.2	35.8	29.4	38.9	47.7	35.1	38.3	50.9	38.5
Oil									
LFO & Kerosene	33.0	36.0	31.2	15.4	22.0	15.8	8.7	14.5	8.9
Diesel Fuel	4.8	5.3	5.2	6.3	6.5	6.4	7.4	7.4	7.3
HFO	1.4	2.4	1.2	0.5	1.4	—	—	0.8	—
LPG	4.3	3.9	0.8	4.4	3.6	0.8	4.3	3.8	0.8
Other Renewables	0.2	0.6	—	1.0	3.5	0.4	2.4	5.8	2.4
Coal	0.4	0.4	0.2	0.3	0.4	0.1	0.3	0.4	—
Electricity	25.6	28.3	23.4	33.2	37.8	28.8	38.5	41.9	31.0
TOTAL[2]	100	—	—	100	—	—	100	—	—

[1] Submittors refers to only Gulf, Imperial, Petro-Canada, Shell and Texaco as they were the only Submittors providing forecasts of all energy forms.
[2] Do not necessarily add to 100 percent as the high and low market shares often represent different Submittors.

6.3 Demand in the Commercial Sector

Views of Submittors

Gulf, Imperial, Petro-Canada, Shell, and Texaco provided forecasts of total commercial energy demand in Canada. As shown in Table 6-5, the Submittors forecasted average annual growth rates, for the period 1980 to 2000, ranging from 3.4 percent by Petro-Canada to 1.3 percent by Shell. Petro-Canada's growth rate reflected relatively high growth in service-oriented activities. Shell's growth rate, on the other hand, reflected slow growth in commercial activity, conservation, and improved energy efficiency in new buildings.

Most Submittors indicated that growth in commercial energy demand was expected to slow from the average annual rate of ten percent experienced during the 1960s and early 1970s. The major factors leading to this slower growth were the reduced pace of commercial activity and price-induced energy conservation and technological change. The degree of the expected slowdown in energy demand varied by Submittor depending on what assumptions were made regarding these major determinants.

Different measures of commercial activity were used by the Submittors. The most prominent of these were output and employment in the service sector. Regardless of the measure used, most Submittors forecasted slower than historical growth. The underlying factors causing this slow growth were given as slower population growth, government spending restraints and the highly developed nature of the current service infrastructure, e.g. schools, hospitals, office buildings, shopping centres.

Gulf, which analyzed commercial activity in more detail, indicated that the only source of strength would come from the indirect effects of accelerated energy activity on other services, namely business services and finance, real estate and insurance. Modest growth was projected for wholesale, retail and other government services (education and hospitals), while slow growth was projected for public administration due to government spending restraints and slower population growth.

Those Submittors providing estimates of energy conservation in existing buildings indicated savings ranging between 7 and 20 percent by the year 2000. For example, the Ontario government projected energy savings over the next 20 years of 7 percent for hotels, restaurants, recreational buildings and warehouses, 14 percent for retail stores, and 17 percent for office buildings. These savings related largely to minor structural changes and improved management of energy use in heating, lighting and air-conditioning.

In addition, most Submittors foresaw high potential energy savings in the construction and design of new commercial buildings. Imperial assumed that almost all new commercial buildings would use electricity. Internal heat generated by light, human occupancy and equipment would effectively meet requirements for space heating. Imperial estimated reductions in energy use averaging about 50 percent compared with existing buildings. TCPL stated that new energy efficient buildings such as Hydro Place in Toronto and Gulf Canada Square in Calgary use less than a quarter of the energy per square foot of comparable pre-1977 buildings. TCPL estimated energy savings in new commercial buildings of 25 percent in 1980, 60 percent in 1990, and 80 percent in 2000.

Most Submittors forecasted the continued displacement of fuel oil by natural gas and electricity. Natural gas was expected to experience the greatest growth in the 1980s. This growth reflected continued conversion of existing customers from oil to natural gas and the extension of natural gas pipelines to Québec and the Maritimes and to Vancouver Island. Conversions were expected to occur to the greatest extent in Ontario and in Eastern Canada where fuel oil's price disadvantage would foster growth patterns similar to those that have occurred in Western Canada. With regard to the new construction market, opinions varied as to what proportion of new buildings would use electricity. Most Submittors indicated that both natural gas and electricity would be used in new buildings. However, due to relative price changes favouring electricity and to the potential for technological advances in heat pumps and waste heat recovery systems, electricity was expected to capture a greater proportion of new buildings in the 1990s.

Imperial's opinion regarding interfuel competition varied slightly from that of most Submittors. Imperial assumed that almost all new buildings would use electricity and internally generated heat. Existing oil-heated buildings were assumed to convert to natural gas at the rate of three percent per year. As a result, oil's market share declined from 19 percent in 1980 to 3.5 percent in the year 2000. The market share of natural gas declined from 43.2 percent in 1980 to 20.7 percent in 2000. Electricity's market share increased substantially from 35.6 percent in 1980 to 69.6 percent in 2000. However, Imperial indicated that a key uncertainty in its forecast was the pace at which old buildings would be replaced by new, energy efficient complexes using mainly electricity.

Shell also provided a different viewpoint regarding interfuel competition. This opinion was largely predicated on the assumption that electricity would maintain its present competitive position with fuel oil and natural gas. As a result, Shell forecasted an increased share of natural gas accompanied by a decline in that of oil. Electricity's share remained essentially unchanged throughout the forecast period. Shell did acknowledge, however, that there was a possibility that electricity could improve its competitive position.

Those Submittors who provided supplemental forecasts of energy demand after the announcement of the NEP indicated that the main impact of the NEP would be a reduction in oil demand. This reduction would be accompanied by increases in demand for both electricity and natural gas. The projected increase in natural gas demand was largely attributed to gas expansion and increased conversions from oil to natural gas in the 1980s. The increasing use of electricity was associated with its improved price competitiveness in the later years of the forecast.

Most Submittors indicated that on a national basis the federal government's target of a ten percent oil market share would likely be reached in the commercial sector by 1990. Petro-Canada and Norcen projected an oil market share of 11 percent in 1990. Gulf, which included agriculture in the commercial sector, stated that priority uses in this category alone would exceed the ten percent market share for oil.

Those Submittors providing supplemental forecasts or comments on a provincial basis did not expect that the Government's target could be achieved in Québec and the Maritimes. TCPL stated that a lot of effort would be required in increasing conservation and expanding natural gas service in order to reach the ten percent target east of Ontario.

Table 6-5

TOTAL ENERGY DEMAND IN THE COMMERCIAL SECTOR - CANADA
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000	AAI-% 1980-2000
Gulf(1)	955	987	1 080	1 241	1 423	2.0
Imperial	730	805	905	1 033	1 186	2.5
Petro-Canada(1)	847	920	1 114	1 366	1 655	3.4
Shell(1)	739	794	857	903	949	1.3
Texaco	930	1 005	1 132	1 299	1 578	2.7
NEB	905	978	1 049	1 175	1 393	2.2

(1) Supplemental Forecast
AAI - Average Annual Increase

Views of the Board

Canadian commercial energy demand grew at an average annual rate of approximately ten percent between 1958 and 1973. Slower commercial activity and rising real energy prices have slowed this rate of growth considerably over the last five years of complete historical data. Between 1973 and 1978 commercial energy demand grew at an average annual rate of 2.8 percent. The Board expects that this slower growth in commercial energy demand will continue over the next two decades. Total commercial energy demand is forecast to grow from a level of 905 petajoules in 1980 to 1 393 petajoules in the year 2000 as shown in Table 6-6. This represents an average annual growth rate of 2.2 percent over the forecast period. The Board's forecast is compared to the Submittors' forecasts in Figure 6-2.

Canadian commercial energy demand growth is expected in Western Canada and the Atlantic Provinces to be greater than the Canadian average. This greater growth reflects the indirect effect of energy investment on commercial activity in these regions. Between 1980 and 2000, commercial energy growth is projected to increase at an average annual rate of 2.7 percent in the Western provinces, 1.9 percent in Québec and Ontario combined, and 2.3 percent in the Atlantic provinces.

The Board expects the continued displacement of fuel oil by natural gas and electricity in the commercial sector as shown in Table 6-7. Natural gas is forecast to increase its market share from 43.1 percent in 1980 to 49.7 percent in 1990, as a result of conversions from fuel oil to natural gas and the extension of natural gas pipelines to Québec City and the Maritimes and to Vancouver Island. After 1990, the market share of natural gas declines modestly to 47.9 percent in 2000, reflecting

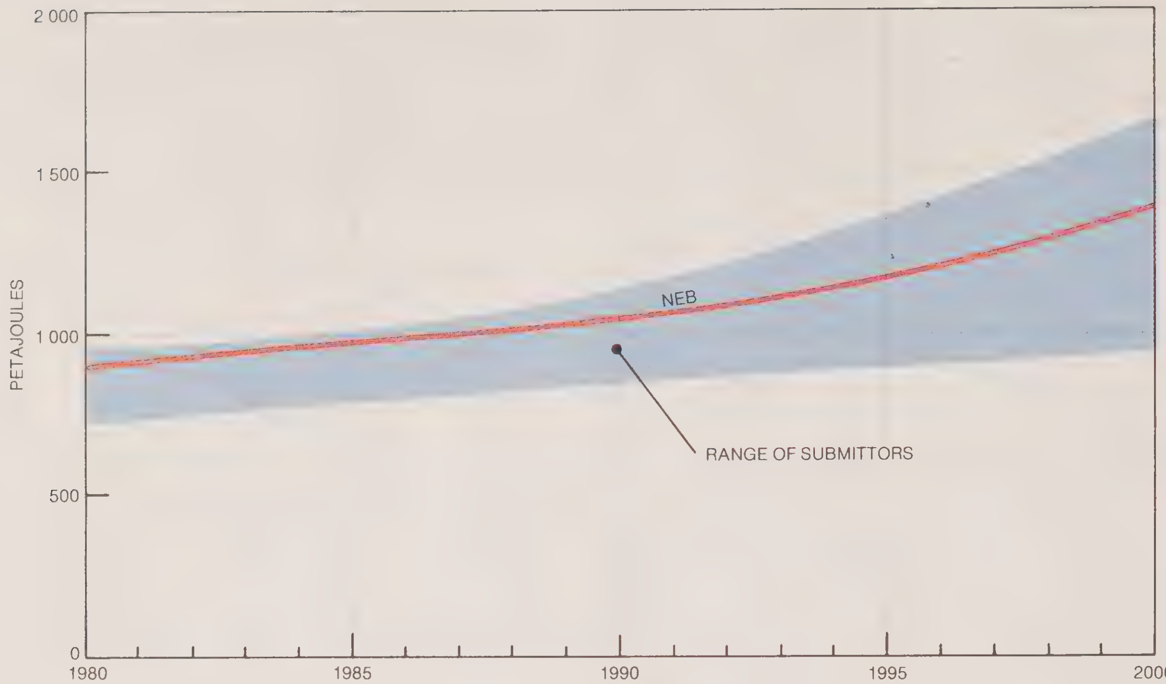

Figure 6-2 Energy Demand in the Commercial Sector
Comparison of Forecasts

Table 6-6

DEMAND IN THE COMMERCIAL SECTOR BY ENERGY FORM - CANADA
Comparison of Forecasts
(Petajoules)

Energy Form	1980			1990			2000		
	NEB	Submittors		NEB	Submittors		NEB	Submittors	
		High	Low		High	Low		High	Low
Natural Gas	390	373	261	522	531	308	666	778	245
Oil									
LFO & Kerosene	130	149	95	54	79	34	35	58	26
Diesel Fuel	22	78	15	21	103	9	22	133	8
HFO	67	97	45	23	61	4	12	64	1
LPG	0	21	0	0	23	0	0	103	0
Other Renewables	0	2	0	8	19	0	31	96	28
Coal	0	2	0	0	2	0	0	2	0
Electricity	296	334	261	422	515	304	625	825	331
TOTAL[1]	905	955	730	1 049	1 132	857	1 393	1 665	947

[1] Not necessarily the sum of above energy forms as the high and low demand for particular energy forms often represent different Submittors.

Table 6-7

DEMAND IN THE COMMERCIAL SECTOR BY ENERGY FORM - CANADA
MARKET SHARES
Comparison of Forecasts
(Percent)

Energy Form	1980			1990			2000		
	NEB	Submittors(1)		NEB	Submittors(1)		NEB	Submittors(1)	
		High	Low		High	Low		High	Low
Natural Gas	43.1	43.2	35.3	49.7	48.3	34.0	47.9	50.7	20.7
Oil									
LFO & Kerosene	14.4	15.6	10.6	5.1	9.0	3.0	2.5	6.1	1.7
Diesel Fuel	2.4	8.2	1.8	2.0	9.5	0.8	1.6	9.3	0.5
HFO	7.4	10.4	6.2	2.2	5.4	0.4	0.9	4.1	0.1
LPG	0	2.2	0	0	2.2	0	0	2.1	0
Other Renewables	0	0.2	0	0.8	1.7	0	2.2	6.7	1.7
Coal	0	0.2	0	0	0.2	0	0	0.2	0
Electricity	32.7	35.9	29.1	40.3	56.9	35.5	44.9	69.6	34.9
TOTAL(2)	100	—	—	100	—	—	100	—	—

(1) Submittors refers to Gulf, Imperial, Petro-Canada, Shell and Texaco as they were the only Submittors providing forecasts of all energy forms.
(2) Do not necessarily add to 100 as the high and low market shares often represent different Submittors.

electricity's improved price competitiveness and the gains made by solar energy in the commercial sector. Electricity's market share increases from 32.7 percent in 1980 to 44.9 percent in the year 2000. The result is that oil's market share is forecast to decline from 24.2 percent in 1980, to 9.2 percent in 1990 and to 5.0 percent in the year 2000.

The Board expects that the NEP goal of reducing oil use in the commercial sector to no more than ten percent of total energy consumed will be achieved in Ontario and the Western provinces by 1990. In Québec the ten percent oil market share will be reached by 1994. In the Atlantic provinces, even assuming rapid growth in electricity demand and significant natural gas penetration in Nova Scotia and New Brunswick, the NEP goal is not expected to be reached within the forecast period. By the year 2000, the oil market share is projected to be 47.1 percent in Newfoundland, 44.2 percent in Prince Edward Island, 18.1 percent in Nova Scotia and 15.1 percent in New Brunswick.

6.4 Demand in the Petrochemical Sector

Introduction

Petrochemical feedstocks include ethane, propane, butanes, natural gas and oil. The category 'oil' covers not only products of oil refining operations such as naphtha, gas oil, and refinery gases, but also pentanes plus and bitumen.

Petrochemical products include ammonia, methanol, ethylene and benzene, and their primary derivatives, particularly ethylene derivatives.

Since there is a direct relationship between petrochemical products and those feedstocks used to produce them, it is more meaningful to consider each feedstock separately as it relates to particular petrochemical products or production centres rather than to discuss total demand covering all feedstocks. For example, almost the entire production of ammonia and methanol in Canada is based on natural gas feedstock. On the other hand, benzene can be produced only from liquid feedstocks. While ethylene production in Ontario and Québec is based on liquid feedstocks, its production in Alberta uses gaseous feedstocks. Submittors generally expected such patterns to continue until the end of the forecast period.

This section is, therefore, organized under the following headings: ethane, propane and butanes, natural gas, oil and total petrochemical demand.

It should be noted that there is a wide disparity in Submittors' estimates of feedstock and fuel requirements in 1980, the starting year of the forecast. The differences seem attributable mainly to differences in the petrochemical products covered, the inclusion or exclusion of fuel requirements and the definition of feedstock. Petrosar, used a mass-related approach rather than a volume-related approach to estimate liquid feedstock demand. Also, it appears that some Submittors did not adequately include feedstocks produced and used internally.

Views of Submittors

Ethane

Submittors' forecasts of petrochemical demand for ethane are compared in Table 6-8.

With the exception of Imperial which forecast ethane demand to be 164 petajoules, projections of Submittors for the year 2000 ranged between TCPL's forecast of 120 petajoules and Shell's forecast of 140 petajoules.

All of the domestic demand for ethane was forecast to be used as a feedstock in ethylene production in Alberta. Imperial's forecast of ethane demand assumed four new world-scale ethylene plants, of which two were expected to come on-stream in the 1980s. Shell expected three additional ethane-based plants to be constructed in Alberta by 1990, each equal in size to the Alberta Gas Ethylene (AGE) plant. Dome, NOVA and TCPL expected two ethane-based ethylene plants to be added to the existing AGE plant before 1990. NOVA assumed the annual capacity of the existing AGE plant to be 545 kilotonnes and that of each of the two additional plants to be 680 kilotonnes. TCPL estimated ultimate annual production capacity of each of the three ethylene plants to be 628 kilotonnes.

TCPL specified ethane requirements per tonne of ethylene to be 52 gigajoules. Neither NOVA nor Shell explicitly specified their ethane requirements per tonne, but the implied values were 72 and 64 gigajoules of ethane per tonne of ethylene respectively.

Table 6-8

ETHANE DEMAND IN THE PETROCHEMICAL SECTOR - CANADA
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000	AAI-% 1980-2000
Dome	28	86	134	128	128	7.9
Imperial	36	62	98	130	164	7.9
NOVA	39	101	138	138	138	6.5
Shell[1]	35	35	140	140	140	7.2
TCPL	30	75	115	120	120	7.2
NEB	39	101	135	135	135	6.4

[1] Supplemental Forecast
AAI—Average Annual Increase

Propane and Butanes

Tables 6-9 and 6-10 compare the Submittors' forecasts of petrochemical demand for propane and butanes.

Currently, only small quantities of propane and butanes are used in the petrochemical sector, mainly in the production of ethylene. Among Submittors, Imperial and NOVA forecast significant increases, in petrochemical use of propane of 25 petajoules and 67 petajoules respectively, over the period 1980 to 2000. They also foresaw some growth in demand for butanes of 6 petajoules and 20 petajoules, respectively. Gulf expected demand for both propane and butanes to remain constant at the 1980 level. Dome projected an increase in demand for butanes but a decline for propane.

Imperial and Dome indicated that their forecasts were based on an analysis of petrochemical plant use. NOVA's projections anticipated a world-scale ethylene plant, based on propane and butanes, to come on stream in Alberta in 1990. The plant would have an annual capacity of 680 kilotonnes and would require, at full capacity, 67 petajoules of propane and 20 petajoules of butanes per year.

Table 6-9

PROPANE DEMAND IN THE PETROCHEMICAL SECTOR - CANADA
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000	AAI-% 1980-2000
Dome	10	7	7	7	7	−1.8
Gulf[1]	5	5	5	5	5	0.0
Imperial	9	15	13	23	34	6.9
NOVA	—	—	67	67	67	—
NEB	9	15	48	79	79	11.5

[1] Supplemental Forecast
AAI—Average Annual Increase

Table 6-10

BUTANES DEMAND IN THE PETROCHEMICAL SECTOR - CANADA
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000	AAI-% 1980-2000
Dome	10	14	14	16	19	3.4
Gulf[1]	3	3	3	3	3	0.0
Imperial	15	14	15	17	21	1.7
NOVA	—	—	20	20	20	—
Shell[1]	4	4	4	4	4	0.0
NEB	8	9	20	29	30	6.8

[1] Supplemental Forecast
AAI—Average Annual Increase

Natural Gas

Petrochemical demand for natural gas arises mainly from its use as a feedstock and fuel in the production of ammonia and methanol and as a fuel in the manufacture of ethylene and its derivatives. Submittors projected petrochemical demand for natural gas on the basis of estimates of future gas-based petrochemical capacity (ethylene, ammonia and methanol) coupled with assumptions regarding feedstock and/or fuel requirements per tonne of capacity. Table 6-11 compares Submittors' forecasts of demand for natural gas in the petrochemical sector in Canada.

Submittors' forecasted average annual rates of growth in petrochemical gas demand ranged from a high of 5.1 percent by TCPL to a low of 1.9 percent by Texaco and Norcen. The annual rates of growth projected by Gulf, Imperial, Petro-Canada and Shell were, however, confined to the relatively narrow range of 3.4 percent to 3.9 percent.

TCPL provided comprehensive details about its assumptions regarding expansion of ethylene, ammonia and methanol capacity and respective feedstock and fuel requirements. With the exception of NOVA, TCPL was the only Submittor giving separate estimates of gas fuel requirements for ethylene production, which were forecast to increase from 12 petajoules in 1980 to 50 petajoules in 2000. This forecast assumed three ethane-based world-scale plants in Alberta before 1990, with gas fuel requirements of 28.3 gigajoules per tonne for the first two plants and 24.0 gigajoules per tonne for the third.

Regarding expansion of ammonia capacity, TCPL expected capacity to increase by 2 758 kilotonnes by 1991. The increase would consist of gas-based ammonia plants proposed in Alberta by Esso Chemical and Sherrit Gordon, plus two additional plants of 500 kilotonnes each, also in Alberta; and two plants, each with an annual capacity to produce 440 kilotonnes, which would be located in British Columbia. Natural gas feedstock requirements for all these plants were assumed to be 28 gigajoules per tonne while fuel requirements were assumed to be 11 gigajoules per tonne. TCPL forecast total requirements of natural gas used as fuel for upgrading ammonia to increase from 10 petajoules in 1980 to 19 petajoules in 1990, after which it would decline to 5 petajoules by 2000 as a result of substitution by coal.

With respect to methanol capacity, TCPL anticipated that the capacity of the Alberta Gas Chemicals (AGC) plant in Medicine Hat would be doubled by 1982 from its present level of 380 kilotonnes. A methanol plant proposed by Celanese Canada to be located in Edmonton, with an annual capacity of 700 kilotonnes, was also expected to be commissioned by mid-1982. A third world-scale plant equal in capacity to the Celanese plant was forecast for Alberta in 1983/84. TCPL also expected the methanol plant announced by Ocelot Industries in British Columbia to come on stream in 1983. TCPL assumed natural gas feedstock for methanol to be 37.8 gigajoules per tonne and fuel requirements to be 1.5 gigajoules per tonne.

TCPL's forecast of petrochemical demand for natural gas also included fuel requirements for other primary petrochemicals using non-gas feedstocks. These included plants to produce benzene, carbon black and olefins in Alberta. The annual gas fuel requirement was estimated to be 19.3 petajoules by 2000.

Imperial forecast substantial expansion of petrochemical capacity, part of which was assumed to be based on coal. Ammonia capacity was estimated to increase by 3 470 kilotonnes and methanol capacity by 2 270 kilotonnes, with one ammonia plant and one methanol plant, based on coal and the remainder on gas.

Gulf forecast six new ammonia plants, each producing 363 kilotonnes per year, to come on stream during the period 1982 to 1994. While, like TCPL, Gulf expected doubling of the methanol capacity of the AGC plant, and construction of new methanol plants by Celanese and Ocelot, it did not, like TCPL, foresee further expansion of methanol capacity.

Shell's estimate of new ammonia capacity was lower than that of TCPL and Gulf; however, its estimate of methanol capacity was higher than Gulf's. In regard to ammonia, Shell assumed two plants, Esso and Sherrit Gordon, to be completed in 1983. With respect to methanol, in addition to a world-scale plant producing 438 kilotonnes, and proposed plants by Celanese and Ocelot, Shell also included a plant announced by WTCL to be constructed in British Columbia in 1985.

Texaco, Norcen and Petro-Canada did not provide details regarding anticipated petrochemical plants or feedstock and fuel requirements.

NOVA was the only Submittor to furnish a separate forecast of requirements of natural gas in the production of ethylene derivatives. Separate requirements were identified for polyethylene, ethylene oxide, ethylene dichloride, ethyl benzene and the category 'other derivatives'. The forecast was based on estimated consumption of these derivatives combined with assumptions regarding gas fuel required per tonne of derivative production. Total Canadian demand for gas used as a fuel for ethylene derivatives was projected to increase from 26 petajoules in 1980 to 87 petajoules in 2000.

Table 6-11

NATURAL GAS DEMAND IN THE PETROCHEMICAL SECTOR - CANADA
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000	AAI-% 1980-2000
Gulf(1)	108	167	189	214	227	3.8
Imperial	80	117	146	172	172	3.9
Norcen(1)	186	229	250	267	269	1.9
Petro-Canada(1)	188	238	279	324	370	3.4
Shell(1)	167	266	336	336	336	3.5
Texaco(1)	186	230	250	269	269	1.9
TCPL(1)	109	221	274	294	295	5.1
NEB	177	295	338	347	352	3.5

(1) Supplemental Forecast
AAI—Average Annual Increase

Oil

In the petrochemical sector, Submittors agreed that oil is consumed mainly as a feedstock in the production of ethylene and aromatics. Almost the entire current petrochemical demand for oil was stated to occur in Québec and Ontario. Submittors, however, expected a substantial part of future growth in demand to occur in Alberta.

Dome, Gulf, Imperial, Petro-Canada, Petrosar, Shell, TCPL, Texaco and Union Carbide submitted forecasts of petrochemical demand for oil in Canada shown in Table 6-12. NOVA limited its estimate to demand for oil used in ethylene production.

Table 6-12

OIL DEMAND IN THE PETROCHEMICAL SECTOR - CANADA
Comparison of Forecasts[2]
(Petajoules)

	1980	1985	1990	1995	2000	AAI-% 1980-2000
Dome	162	227	261	267	270	2.6
Gulf[1]	199	314	327	319	307	2.2
Imperial	202	248	273	294	347	2.7
NOVA	153	153	164	317	442	5.4
Petro-Canada[1]	190	253	263	246	231	1.0
Petrosar[1]	263	417	424	535	616	4.3
Shell[1]	210	249	250	256	260	1.1
TCPL[1]	130	248	286	332	335	4.8
Texaco[1]	198	290	341	341	341	2.8
Union Carbide[1]	204	253	313	313	413	3.6
NEB	156	213	221	264	389	4.7

(1) Supplemental Forecast
(2) Converted using the factor 39.10676 GJ/m^3
AAI—Average Annual Increase

The average annual rates of growth in demand ranged from one percent by Petro-Canada to 5.4 percent by NOVA, with forecasts by Dome, Gulf, Imperial, Shell and Texaco being near the lower end of the range and those by Petrosar, TCPL and Union Carbide being closer to the higher end.

NOVA expected oil-based ethylene capacity to increase by 1 493 kilotonnes over the forecast period. The increase would result from the construction of new world-scale plants in Sarnia and Alberta, with respective capacities of 550 kilotonnes and 680 kilotonnes, and the expansion of 263 kilotonnes in capacity in Québec. The Sarnia plant would be based on gas and residual oils, while the Alberta plant would use bitumen as feedstock.

Petrosar expected growth in both ethylene and benzene capacities. Liquid-based ethylene capacity was forecast to expand by 675 kilotonnes, consisting of an increase of 225 kilotonnes in Québec during 1980-85 and of 450 kilotonnes in Ontario during 1990-95. Feedstock requirements were assumed to be 10.4 cubic metres (406.7 gigajoules) per tonne of ethylene and fuel requirements to be 8.3 percent of feedstock requirements.

Petrosar expected benzene plants proposed by Shell and Petalta to come on stream in Alberta during 1984. The first plant would process synthetic crudes and the second, pentanes plus. Production capacities of the two plants would be 235 kilotonnes and 340 kilotonnes, respectively. The combined annual feedstock requirements for the two benzene plants were estimated by Petrosar to be one million cubic metres (39 petajoules).

TCPL's forecast of petrochemical demand for oil was based mainly upon anticipated construction of new plants in Alberta and to a lesser extent, on expansion of capacity in Ontario and Québec. New petrochemical plants assumed for Alberta were:

(i) a 500 kilotonne benzene plant in 1985;
(ii) a 50 tonne carbon black plant in 1991; and
(iii) an olefins plant in 1992.

Imperial and Shell expected substantial growth in oil feedstock demand in Alberta but modest or little growth in Ontario and Québec. Gulf foresaw significant growth in both Alberta and Québec. While these Submittors did not specify underlying estimates of expansion of oil-based ethylene capacity in Québec and Ontario, their forecast requirements for these provinces implied lower expected growth of such capacity than anticipated by Petrosar. In particular, Shell forecast almost flat demand for liquid feedstocks in Ontario and Québec.

Regarding expansion of benzene capacity, both Imperial and Shell anticipated new plants by Petalta and Shell to be operating in Alberta by 1985.

Total Petrochemical Demand

Submittors' forecasts of total petrochemical demand for feedstock and fuel are given in Table 6-13. Projections by NOVA and Petrosar excluded natural gas requirements for ammonia and methanol.

High rates of growth forecast by NOVA and Petrosar were due mainly to their projection of substantial growth in LPG and liquid-based ethylene capacity. Petrosar also expected a significant increase in benzene capacity.

TCPL and Imperial forecast relatively high rates of growth in petrochemical demand although TCPL's forecast was higher than Imperial's. While Imperial's forecast average annual rate of increase in LPG demand was higher, it was more than offset by TCPL's projection of petrochemical demand for oil and gas.

Table 6-13

TOTAL FEEDSTOCK AND FUEL DEMAND IN THE PETROCHEMICAL SECTOR - CANADA
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000	AAI-% 1980-2000
Gulf[1]	315	489	524	541	542	2.8
Imperial	343	456	545	636	766	4.1
NOVA	224	315	476	641	776	6.4
Shell[1]	416	555	730	736	740	2.9
Petro-Canada[1]	378	491	541	570	600	2.3
Petrosar[1]	348	550	616	771	901	4.9
TCPL[1]	269	544	675	746	750	5.3
Texaco[1]	439	610	700	719	719	2.5
NEB	389	633	762	854	985	4.8

(1) Supplemental Forecast
AAI—Average Annual Increase

Gulf, Shell and Texaco projected rates of growth in demand in the narrow range between 2.5 and 2.9 percent. Texaco forecast a higher rate of growth in petrochemical oil demand than Gulf and Shell; however, this was more than offset by higher growth in demand for LPG and natural gas projected by Gulf and Shell.

The NEP stipulated that, 'The Petrochemical Industry should not plan on using more oil in 1990 than it does now ...,' since 'for most petrochemical processes, feedstocks other than oil will do.'

With the exception of Petro-Canada, Submittors generally stated that the NEP would have little or no effect on petrochemical demand for oil. Gulf, Shell, Petrosar and Union Carbide maintained their post-NEP forecasts of petrochemical demand for oil at pre-NEP levels, while Texaco reduced its estimates by about five percent throughout the forecast period. Petro-Canada, however, reduced its pre-NEP oil forecast by 30 percent in 1985, 36 percent in 1990 and 53 percent in 2000.

Submittors gave four reasons to justify their view that the NEP provision regarding use of oil for petrochemicals at current levels in 1990 was not realistic. Firstly, for 35 percent of the primary petrochemicals currently produced in Canada, feedstocks other than oil cannot be used. Secondly, oil used as a feedstock in ethylene production yields co-products such as butadiene and aromatics, which are used in downstream operations in the petrochemical centres of Sarnia and Montreal. Use of ethane or propane would yield small and insufficient quantities of these co-products, thereby affecting the chain of interdependence, and hence output and employment, in these petrochemical complexes. Thirdly, petrochemical demand for oil accounts for only five percent of the demand for total refined petroleum products, and petrochemical use is an optimum disposition of the resource. Finally, it was argued that increased production of oil-derived petrochemicals need not lead to a growing demand for oil, since by using less desirable crude fractions and low octane streams, and by upgrading heavy fuel oil, petrochemical feedstock supply can be increased, without a corresponding increase in demand for crude oil.

Views of the Board

The Board's forecast of petrochemical feedstock and fuel demand for ethane, propane, butanes, natural gas, and oil is based upon estimates of additional petrochemical capacity expected to come on-stream during the forecast period and upon assumptions regarding feedstock and fuel requirements per unit of capacity. Petrochemicals considered are ammonia, methanol, ethylene, benzene, and their primary derivatives.

Estimates of additional petrochemical capacity by type of feedstock are based on projections of the domestic plus export demand for the various petrochemical products. Assumptions regarding feedstock and fuel requirements take into account expected conservation in response to escalating energy prices.

Table 6-13 and Figure 6-3 compare the Board's forecast of total energy demand in the petrochemical sector with forecasts of the Submittors. The ethane and natural gas-based petrochemical plants forecast by the Board to come on-stream during the forecast period, and their feedstock and fuel requirements, are summarized in Table 6-14. Similar information on LPG and oil-based plants is presented in Table 6-15.

Table 6-14

ETHANE AND NATURAL GAS-BASED PETROCHEMICAL PLANTS
NEB Forecast

Province	Petrochemical	Company	Estimated Annual Capacity	On-Stream Date	Annual Feedstock/Fuel Requirements At Full Capacity
Alberta	Ethylene	AGE	680 KT	Mid-1984	$2.62 \times 10^6 \times m^3$ Ethane (48.2 PJ), 7.6 PJ Gas
Alberta	Ethylene	AGE	680 KT	Mid-1985	Same as above.
Alberta	Ammonia	Esso Chemical	584 KT	1983	20.4 PJ
Alberta	Ammonia	Sherritt Gordon	365 KT	1983	12.7 PJ
Alberta	Ammonia	N.A.	885 KT	1987	25.7 PJ
Alberta	Ammonia	N.A.	365 KT	1987	10.5 PJ
Alberta	Methanol	Alberta Gas Chemicals	398 KT	1982	15.3 PJ
Alberta	Methanol	Celanese	765 KT	1983	29.3 PJ
B.C.	Methanol	Ocelot	405 KT	1982	15.4 PJ
B.C.	Ammonia	N.A.	400 KT	1995	11.6 PJ
Ontario	Ammonia	N.A.	420 KT	1984	11.6 PJ

Table 6-15

LPG AND OIL-BASED PETROCHEMICAL PLANTS
NEB Forecast

Province	Petrochemical	Company	Estimated Annual Capacity	On-Stream Date	Annual Feedstock/Fuel Requirements At Full Capacity[1]
Alberta	Benzene	Petalta and Shell	575 KT	1985	$1 \times 10^6 \times m^3$ pentanes plus (39.1 PJ)
Alberta	Ethylene	—	680 KT	1998	$3.2 \times 10^6 \times m^3$ Bitumen (125.1 PJ)
Quebec	Ethylene	Petromont	Two stage expansion from 287 KT in 1980 to 350 KT in 1985 and to 550 KT in 1991	1991	$2.7 \times 10^6 \times m^3$ (105.6 PJ)
Alberta	Ethylene	—	680 KT	1990	$2.6 \times 10^6 \times m^3$ Propane (66.8 PJ) $0.7 \times 10^6 \times m^3$ Butanes (20.0 PJ)

(1) Oil-based petrochemical feedstocks are converted using the factor 39.10676 GJ/m^3.

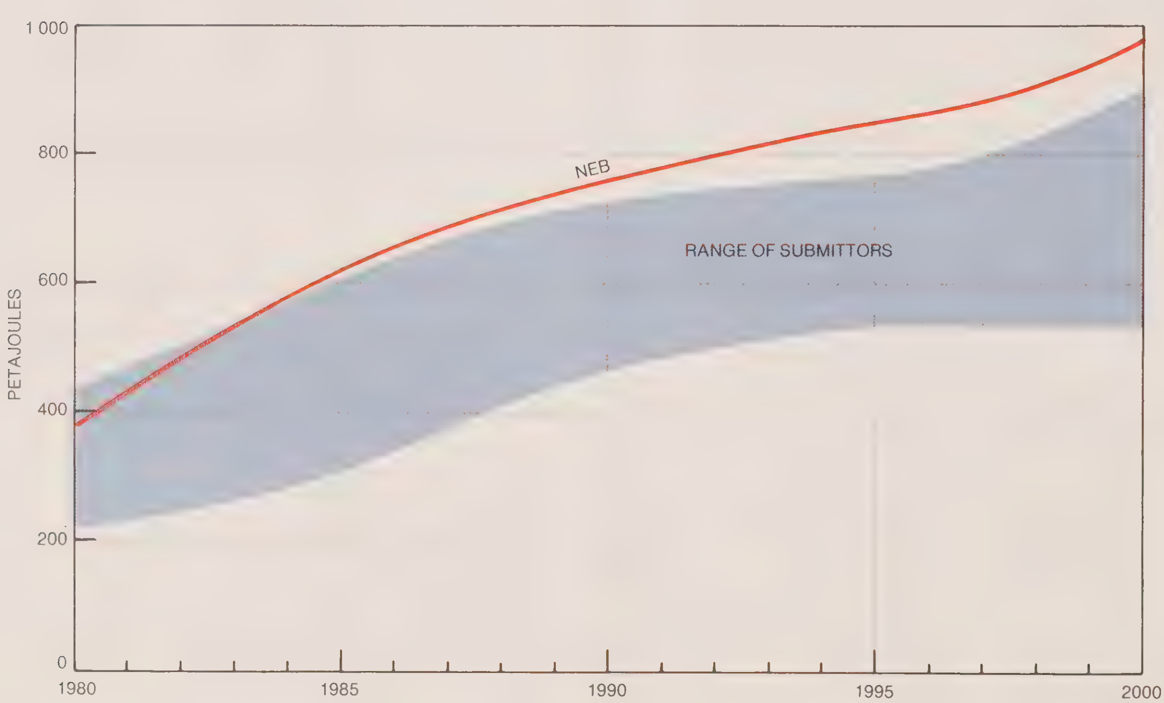

Figure 6-3 Demand for total Petrochemical Feedstocks and Fuel Comparison of Forecasts

Ethane

AGE operates the only world-scale ethylene plant based on ethane. As did NOVA, Dome and TCPL, the Board forecasts two additional ethane-based ethylene plants to come on-stream in Alberta by 1985. The forecast of ethane requirements is based on NOVA's estimates.

Propane and Butanes

Consistent with the Board's forecast of demand for ethylene and the evidence of NOVA, it is expected that an LPG-based world-scale ethylene plant will come on-stream in 1990. The use of LPG as the expected feedstock for this plant is also consistent with the NEP guidelines on choice of feedstock.

Natural Gas

The Board's projected construction of ammonia plants by Esso and Sherrit Gordon, and of methanol plants by AGC, Celanese and Ocelot is consistent with evidence by Shell and TCPL. The Board's forecast of further additions to ammonia capacity is derived from the long term forecast of the domestic plus export demand for ammonia and is comparable to evidence on the expected expansion of ammonia capacity after 1985, given by Gulf, Imperial and TCPL. The Board's projected total increase in natural gas-based ammonia capacity is close to Imperial's and TCPL's forecasts but higher than Gulf's.

Feedstock and fuel requirements for ammonia and methanol are estimated on the expectation that rising energy prices will lead petrochemical producers to introduce innovations designed to reduce feedstock and fuel use per unit of production. Feedstock and fuel requirements per tonne of ammonia are assumed to be 35 gigajoules for plants coming on-stream before 1987 and 29 gigajoules for later plants. Feedstock and fuel demands for methanol are estimated to be 38 gigajoules per tonne.

The Board accepts NOVA's estimates of fuel requirements per unit of ethylene derivatives and has applied them to its own forecast of production of ethylene derivatives.

Oil

The NEP stipulates that petrochemical demand for oil should be no higher in 1990 than it is now. The Board forecasts petrochemical demand for oil to increase by 65 petajoules, from 156 petajoules in 1980 to 221 petajoules in 1990. The following is an explanation of the projected increase.

The demand for oil by the petrochemical sector declined from 190 petajoules in 1979 to 156 petajoules in 1980. The Board assumes that a part of this steep decline, about 12 petajoules, will be restored. In addition, the increase in petrochemical demand for oil resulting from additions to capacity of existing plants and construction of new plants amounts to 53 petajoules for the period 1980-90. Of this quantity, benzene plants, assumed to come on-stream in Alberta in 1985, account for 39 petajoules, with the remaining 14 petajoules being due to expansion of ethylene capacity in Québec. Estimates of additions to benzene capacity and concomitant liquid feedstock and fuel requirements are adopted from Petrosar's forecast. The projected increase in requirements in Québec is based on Petromont's submission.

The resulting forecast increase in petrochemical demand for oil between 1980 and 1990 is much smaller than that projected in the September 1978 Oil Report. Whereas the 1978 Report projected an increase of 159 petajoules in petrochemical demand for oil between 1980 and 1990, the current forecast projects an increase of only 65 petajoules over the same period.

The Board's forecast of petrochemical demand for oil shows an increase of 125 petajoules between 1995 and 2000. This increase is the result of a bitumen-based world-scale ethylene plant which is expected to come on-stream in Alberta in 1997, consistent with the views of NOVA, with the Board's forecast of ethylene demand in Canada, and also with expected petrochemical developments in Alberta.

Total Petrochemical Demand

Table 6-13 shows that the Board's projection of the level of petrochemical demand in 2000 is higher than that of the Submittors. One reason for this is the higher estimate of demand in 1980, the starting year of the forecast, but another explanation lies in the fact that no single Submittor appeared to cover the views of both petrochemical companies and the oil and gas companies. The Board has integrated the evidence of petrochemical companies with that of oil and gas companies. For example, the major cause of the difference between the Board's forecast of total petrochemical demand for the year 2000 and that of TCPL is the Board's acceptance of NOVA's forecast for the construction of an ethylene plant based on propane and butanes. Similarly, the difference between the Board's forecast and those of Gulf and Texaco's is the Board's expectation of two additional ethylene plants, using LPG and bitumen as feedstocks.

6.5 Demand in the Industrial Sector

Views of Submittors

Gulf, Imperial, Petro-Canada, Shell, and Texaco provided complete long range industrial demand forecasts for Canada. These forecasts are compared in Table 6-16 and Figure 6-4.

Table 6-16

TOTAL ENERGY DEMAND IN THE INDUSTRIAL SECTOR - CANADA

Comparison of Forecasts[2]

(Petajoules)

	1980	1985	1990	1995	2000	AAI-% 1980-2000
Gulf[1]	2 316	2 681	3 222	3 746	4 317	3.2
Imperial	2 371	2 722	3 140	3 608	3 975	2.6
Petro-Canada[1][3]	1 928	2 276	2 531	2 780	3 065	2.3
Shell[1]	2 505	2 925	3 318	—	4 070	2.5
Texaco	2 197	2 462	2 784	3 123	3 543	2.4
NEB	2 326	2 589	2 888	3 243	3 833	2.5

[1] Supplemental Forecast.
[2] Includes thermal, industrial and metallurgical coal.
[3] Does not include hog fuel and pulping liquor except some incremental volumes of wood wastes.
AAI—Average Annual Increase

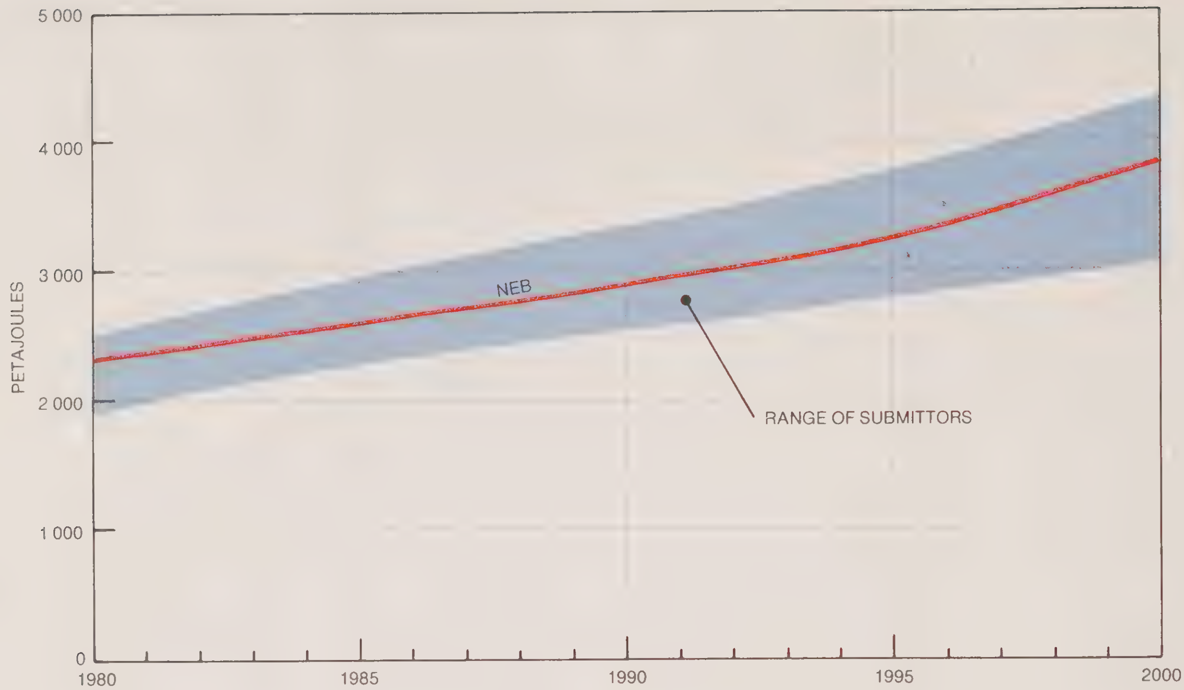

Figure 6-4 Energy Demand in the Industrial Sector
Comparison of Forecasts

There was a general consensus among the Submittors that higher energy prices, increasing conservation and lower economic growth than experienced in the 1960s and early 1970s, would characterize the forecast period. Industrial energy demand was expected to grow at a slower rate than in the past. Changes in relative fuel prices and technological innovations were expected to result in considerable interfuel substitution over the next two decades.

Regionally, it was expected that demand for energy in the western provinces would grow at a faster rate than in the east, reflecting lower prices of energy and/or higher economic growth rates.

Despite many similarities in assumptions among the Submittors, considerable differences existed in the rate at which the demand for energy in the industrial sector was forecast to grow to the year 2000. Differences in the Submittors' forecasts were generally due to varying assumptions with respect to the rate of growth of the Canadian economy, energy prices, conservation, impact of energy-related projects, impact of the NEP and forecasting methodologies.

Gulf forecast the highest rate of growth in the industrial demand for energy in the period from 1980 to 2000. Its forecast was based on the assumption of a high rate of growth in real gross domestic product, modest conservation, and additional energy requirements associated with the development and growth of oil sands, heavy oil, and enhanced recovery projects. Energy requirements related to oil and natural gas exploration and energy related construction activities were also considered in the forecast. Gulf saw little change in industrial activity and industrial energy demand as a result of the NEP.

Petro-Canada forecast the lowest growth in the demand for energy in the industrial sector. It considerably reduced its forecast of demand for energy in the supplemental submission primarily due to the assumption of higher energy prices than those in its original submission.

Differences in definition among the Submittors were common in this sector. For instance, Shell included agricultural use of diesel fuel in the industrial sector. As a result, Shell's estimate of demand for energy for 1980 is the highest of all Submittors. Petro-Canada, unlike the other major Submittors, did not include consumption of hog fuel and pulping liquor, with the exception of some incremental volumes of wood wastes, in its energy demand forecast resulting in the lowest estimate for 1980 among the Submittors.

Growth in resource-based industries in western and eastern Canada, implementation of oil sands projects, and construction of gas pipelines in Québec, the Maritimes, and other regions were considered by a number of Submittors to be some of the major factors affecting demand for industrial energy in the forecast period. With few exceptions, it was generally believed that the NEP would have only a marginal impact on the rate of growth of industrial energy demand.

Most of the Submittors expressed the view that overall energy prices, and especially those of oil and natural gas, would continue to rise in real terms in the forecast period.

Natural gas was expected to achieve a competitive advantage over oil. The reasons given were the oil and natural gas price relationship outlined in the NEP, and the expected reductions in the surplus of residual fuel oil due to upgrading and reduced production.

The price of electricity was assumed by most of the Submittors to rise at the rate of inflation. Some believed that in the short run electricity prices might rise in real terms, but not as rapidly as those of oil and natural gas. Most of the Submittors expected that, in the 1990s, electricity could become competitive relative to gas and particularly to oil in certain regions.

Because of increased capital and labour costs, and environmental restrictions, the price of coal was predicted by a number of the Submittors to increase in real terms. However, coal was forecast to improve its competitiveness relative to other fuels.

Submittors who made a forecast of hog fuel and pulping liquor demand expected increased use, particularly in the pulp and paper industry, as increases in fossil fuel prices made wood wastes increasingly competitive. The market share of wood wastes was forecast to increase noticeably until 1990 and then was expected to stay more or less constant, mainly as a result of supply limitations.

Demand for natural gas in the industrial sector was forecast to show a strong growth in the 1980s, due to its price competitiveness, as pipelines are extended to Québec, the Maritimes, and Vancouver Island, and as efforts are made to displace petroleum products in existing and new markets.

In the 1990s, the rate of increase in the gas market share was expected to slow down. TCPL, along with a small number of other Submittors projected a slight decrease in the gas market share in a number of regions in the second half of the forecast period.

Expansion in industrial natural gas demand was assumed by most Submittors to be mainly at the expense of oil. Electricity was also forecast by a majority of Submittors, including the province of New Brunswick, to expand its share of the industrial energy market by displacing oil.

Some of the Submittors forecast the market share of coal to expand. Strong growth in the demand for coal, mainly at the expense of oil, was forecast by Ontario and Manitoba. Others, like Imperial, expected the share of coal to remain more or less constant throughout the forecast period. Still others predicted a decline in the share of coal in the industrial energy market. However, in most cases, minimal changes were forecast.

Displacement of oil products was most pronounced in the case of heavy fuel oil which was forecast by British Columbia, among others, to lose most of its share of the industrial energy market to natural gas, electricity and other fuels.

Submittors generally expected demand for diesel fuel oil to remain firm or even increase due to an expected lack of substitutable fuels in certain industrial applications and anticipated growth of industrial activity in remote areas.

Most of the Submittors assumed some conservation in energy consumption because of expected increases in real energy prices and energy saving technological innovations. Provinces recognized the potential significance of conservation towards the achievement of both national self-sufficiency in oil and higher degrees of regional self-reliance.

British Columbia, and a number of other Submittors, expressed the view that additional conservation would be relatively modest because, in response to increases in energy prices since 1973, a great deal of conservation in the industrial sector has already been achieved.

Most Submittors' estimates of conservation potential for the industrial sector ranged from 8 percent to 25 percent over the 1979 energy consumption level by the year 2000.

Ontario stated that it was committed to achieving a 25 percent reduction in the energy required per unit of output by 1985 as compared to the 1975 level. Further savings of five to ten percent were assumed to be achieved by the year 2000.

A large number of Submittors, including Nova Scotia and Ontario, expected increasing volumes of renewable and recoverable energy sources to be used. Imperial expressed the view that, by the year 2000, solar energy could capture about 1.5 percent of the industrial energy market. TCPL, on the other hand, did not see any significant potential for solar energy in the industrial sector in the forecast period.

Changes in the energy demand forecast in the supplemental submissions filed after the announcement of the NEP, often incorporated not only the impact of the NEP but also revised and updated economic, demographic and other assumptions. This made it difficult to isolate and quantitatively measure the impact of the NEP on the industrial energy demand forecasts of the various Submittors.

A number of Submittors expected natural gas, and to a lesser extent coal and electricity, to increase their market shares at the expense of oil due to the NEP.

Approximately half of the Submittors, who made some comments about the off-oil policy goal of reducing the market share of oil to ten percent, indicated that the goal was attainable at the national level by 1990. TCPL's comments reflected the views of a number of Submittors, namely, that in eastern Canada, the off-oil policy objective might be achieved, but only with a great deal of additional effort. Imperial and a few others

expressed the view that the goal of the off-oil policy could not be achieved in Québec and the Maritimes at least by 1990, although in some cases the market share of oil might get very near to ten percent.

The provinces, by and large, seemed to be in agreement with the basic objective of the off-oil policy.

Views of the Board

The Board forecasts the demand for energy in the industrial sector to increase from 2 326 petajoules in 1980 to 2 888 petajoules in 1990, and to 3 833 petajoules by the year 2000, as shown in Table 6-17.

The Board's forecast economic growth, real energy prices, and conservation are expected to keep the growth rate of industrial energy demand at about 2.2 percent per year during the 1980s. In the 1990s, industrial demand for energy is forecast to grow at a higher rate of 2.9 percent per year, partly because higher real energy prices and other conservation measures are expected to have had most of their impact by about 1990 and partly because of the forecast of more rapid economic growth in the 1990s.

The Board forecasts the demand for natural gas in the industrial sector to increase from 677 petajoules in 1980, to 1 085 petajoules in 1990, and to 1 560 petajoules by the year 2000. Forecast market shares are presented in Table 6-18. As a result of the improved competitive position of natural gas, expansion in new market areas as well as conversions in existing markets, anticipated reduction in the production of heavy fuel oil in Eastern Canada, and other factors such as security of supply, it is expected that the market share of natural gas in the industrial energy market will increase from 29 percent in 1980, to 38 percent in 1990, and 41 percent by 2000, mainly at the expense of heavy fuel oil.

In the industrial sector, the demand for electricity is projected to increase from 490 petajoules in 1980, to 639 petajoules in 1990, and to 885 petajoules by the year 2000. The market share of electricity is forecast to increase from 21 percent of the industrial energy demand in 1980 to about 23 percent by the end of the forecast period, displacing primarily heavy fuel oil.

Consumption of hog fuel and pulping liquor is forecast to become more economical, especially in the pulp and paper industry, as a result of predicted increases in fossil fuel prices in the 1980s. Consequently, the demand for hog fuel and pulping liquor in the 1980s is projected to grow at a rate second only to that of natural gas. By the end of the first half of the forecast period, most of the available supply of wood wastes is expected to be consumed, resulting in stabilization of its market share. Expansion in the consumption of hog fuel and pulping liquor is assumed to be largely at the expense of oil products.

The market share of coal is predicted to remain stable in the 1980s and to decline very slightly in the later part of the forecast.

As indicated, the increases in the demand for natural gas, electricity, and other fuels are assumed to be mainly at the expense of heavy fuel oil which shows a decline in market share from 16 percent of the industrial energy market in 1980 to five percent in 1990, and to three percent by the year 2000.

In response to expected construction and exploration activities associated with energy projects, and because of the non-substitutable use in certain industrial applications, the demand for diesel fuel oil is projected to increase throughout the forecast period.

Consumption of energy per unit of real domestic product in the industrial sector is expected to decline by about 24 percent in the period from 1980 to 2000.

Table 6-17

DEMAND IN THE INDUSTRIAL SECTOR BY ENERGY FORM - CANADA
Comparison of Forecasts
(Petajoules)

Energy Form	1980			1990			2000		
	NEB	Submittors		NEB	Submittors		NEB	Submittors	
		High	Low		High	Low		High	Low
Natural Gas	677	783	648	1 085	1 342	965	1 560	1 696	1 227
Oil									
LFO & Kerosene	54	71	42	47	53	30	40	52	20
Diesel Fuel	127	199	89	184	306	67	256	475	60
HFO	373	565	337	130	380	116	96	394	55
LPG	11	66	8	11	214	5	13	86	4
Hog Fuel and Pulping Liquor	318	332	201	448	484	277	568	613	324
Other Renewables	0	2	0	10	61	1	25	92	53
Coal: Thermal & Metallurgical	276	326	262	334	520	300	389	929	345
Electricity	490	504	455	639	848	570	885	1 277	667
Total[(1)]	2 326	2 505	1 927	2 888	3 318	2 530	3 833	4 317	3 065

[(1)] Not necessarily the sum of above energy forms as the high and low demand for particular energy forms often represent different Submittors.

Table 6-18

DEMAND IN THE INDUSTRIAL SECTOR BY ENERGY FORM - CANADA
MARKET SHARES
(Percent)

Energy Form	1980			1990			2000		
	NEB	Submittors		NEB	Submittors		NEB	Submittors	
		High	Low		High	Low		High	Low
Natural Gas	29.1	33.7	28.3	37.6	41.9	33.3	40.7	41.7	36.0
Oil									
LFO & Kerosene	2.3	3.2	1.8	1.6	1.8	.9	1.0	1.3	0.6
Diesel Fuel	5.5	7.9	4.1	6.4	9.5	2.4	6.7	11.9	1.7
HFO	16.0	18.2	14.7	4.5	7.3	3.6	2.5	6.5	1.3
LPG	0.5	2.1	0.4	0.4	6.6	0.2	0.3	2.0	0.1
Hog Fuel and Pulping Liquor	13.7	15.1	8.0	15.5	17.4	8.3	14.9	17.3	8.0
Other Renewables	—	0.1	—	0.3	2.4	—	0.7	2.8	1.3
Coal: Thermal & Metallurgical	11.9	14.7	11.1	11.6	13.4	10.8	10.1	12.6	9.7
Electricity	21.1	23.6	19.2	22.1	27.7	18.2	23.1	32.3	16.8
Total[1]	100	—	—	100	—	—	100	—	—

[1] Do not necessarily add to 100 percent as the high and low market shares often represent different Submittors.

It is expected that in the 1980s, the reduction in the consumption of energy per unit of real domestic product will proceed at a faster pace than in the 1990s, partly as a result of a more rapid increase in real energy prices, and partly due to increasing applications of energy-saving technological innovations.

The Board expects the market share of hog fuel and pulping liquor to increase slightly from 13.7 percent to 14.9 percent in the industrial sector over the next two decades. Other renewable energy forms are forecast to increase their market share from virtually zero to 0.7 percent over the same period. The demand for total renewable sources of energy is forecast to increase from 318 petajoules in 1980 to 593 petajoules in 2000.

As a result of the measures announced in the NEP, further expansion in demand for natural gas is forecast, and the availability of heavy fuel oil is assumed to be reduced in eastern Canada from its present level, through upgrading and other measures.

While the demand for heavy fuel oil is expected to decline, the demand for diesel fuel oil is expected to continue to increase due to anticipated growth in industrial activity in remote areas, growth in the energy sector, and its non-substitutable use in certain industrial applications.

The Board expects by 1990 the combined demand for heavy fuel oil, light fuel oil, and kerosene to be well below ten percent of the industrial energy market in all regions except the Atlantic Provinces, where it is reduced from 49 percent in 1980, to 25 percent in 1990, and to 12 percent by the year 2000. A projected market share of oil higher than ten percent reflects continued dependence on oil in Newfoundland and Prince Edward Island, as well as in areas not expected to be serviced by natural gas in New Brunswick and Nova Scotia, plus a minimum level of consumption of oil even in areas with gas service.

In the industrial sector, the off-oil policy goal of reducing total oil share to ten percent is considered by the Board to be achievable at the national level in all regions except the Atlantic region by the year 2000.

6.6. Demand in the Transportation Sector

Views of Submittors

The transportation sector is subdivided into road, rail, air and marine transport. Petroleum products — motor gasoline, diesel, aviation jet fuel, aviation gasoline and heavy fuel oil account for almost the entire demand for energy in this sector.

Submittors expected energy demand in the air sector to grow at the highest rate followed in decreasing order by the rail, marine and road sectors. These differing rates of growth in energy demand reflected mainly differences in each sector with respect to forecasts of economic activity and assumptions regarding potential for conservation.

The overall rates of growth in total energy demand in the transportation sector presented in Table 6-19 ranged between 0.1 percent by Norcen and 1.4 percent by Dome. Submittors generally expected petroleum products to satisfy almost the entire transportation demand for energy in the forecast period. Some Submittors, however, expected some substitution of propane and electricity for motor gasoline in the road sector. Amongst petroleum products, Submittors anticipated substitution of die-

Table 6-19

TOTAL ENERGY DEMAND IN THE TRANSPORTATION SECTOR
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000	AAI-& 1980-2000
Dome	1 932	1 922	2 077	2 287	2 555	1.4
Gulf[1]	1 982	2 082	2 195	2 348	2 542	1.3
Imperial	2 070	2 113	2 133	2 164	2 149	0.2
Norcen[1]	1 875	1 792	1 816	1 790	1 900	0.1
Petro-Canada[1]	1 935	1 936	2 025	2 097	2 231	0.7
Shell[1]	1 835	1 792	1 826	—	2 050	0.6
Texaco[1]	1 877	1 853	1 962	1 940	2 094	0.5
NEB	1 957	2 022	2 121	2 217	2 385	1.0

[1] Supplemental Forecast
AAI - Average Annual Increase

sel for gasoline in road transportation. Submittors also foresaw continued dominance of aviation jet fuel and diesel, as motive fuels in air and rail transportation, respectively.

Gulf, Norcen, Petro-Canada, Shell and Texaco revised their projections of total energy demand in the transportation sector in the light of pronouncements in the NEP. While Gulf and Texaco reduced their pre-NEP estimates by two to three percent in 1990 and 2000, Petro-Canada and Shell made significant downward adjustments, reducing their forecasts by about 10 percent in 1990 and 15 percent in 2000. Norcen reduced its pre-NEP forecast by 6 percent in 1990 and 2000.

Norcen and Texaco did not indicate the sectors to which post-NEP reductions would apply. While Gulf, Petro-Canada and Shell did make some changes to their forecasts in one or more non-road sectors, the major reductions in total transportation demand resulted from downward adjustments in their estimates for road transportation.

Views of the Board

The Board's forecast of total energy demand in the transportation sector is compared to Submittors' forecasts in Tables 6-19 to 6-21 and Figure 6-5, and is the sum of its estimates of demand in the road, rail, air and marine transportation sectors which are discussed in sections 6.6.1 to 6.6.4, respectively.

The Board's forecast average annual rate of growth in total energy demand in the transportation sector is lower than those of Dome (which did not present separate estimates of energy demand in the four sectors) and Gulf but higher than those of other Submittors. The Board's forecast rate of growth is lower than that of Gulf due mainly to the Board's lower projections of demand in the road and air sectors. The Board's projected rate of growth in total demand in the transportation sector is higher than other Submittors due mainly to its higher forecast of demand in road transportation and to a lesser extent, in marine transportation.

Table 6-20

DEMAND IN THE TRANSPORTATION SECTOR BY ENERGY FORM - CANADA
Comparison of Forecasts
(Petajoules)

Energy Form	1980			1990			2000		
	NEB	Submittors		NEB	Submittors		NEB	Submittors	
		High	Low		High	Low		High	Low
Motor Gasoline	1 341	1 379	1 249	1 212	1 330	916	1 115	1 375	674
Diesel	366	433	282	576	600	375	815	943	547
Aviation Jet Fuel	167	176	150	226	254	142	321	350	169
Aviation Gasoline	8	9	8	9	13	7	11	17	7
Heavy Fuel Oil	73	77	61	81	95	74	94	131	81
Propane	2	2	0	17	31	6	28	37	9
Electricity	0	2	0	0	3	0	0	13	0
Total [1]	1 957	2 070	1 835	2 121	2 195	1 816	2 385	2 555	1 900

[1] Not necessarily the sum of the above energy forms, as the high and low demands for particular energy forms often represent different Submittors.

Table 6-21

DEMAND IN THE TRANSPORTATION SECTOR BY ENERGY FORM - CANADA MARKET SHARES

Comparison of Forecasts (Percent)

Energy Form	1980 NEB	1980 Submittors High	1980 Submittors Low	1990 NEB	1990 Submittors High	1990 Submittors Low	2000 NEB	2000 Submittors High	2000 Submittors Low
Motor									
Gasoline	68.5	72.6	66.6	57.1	68.7	50.1	46.8	59.7	32.9
Diesel	18.7	20.9	14.9	27.2	32.8	19.4	34.2	46.0	27.2
Aviation Jet Fuel	8.5	8.8	7.8	10.7	12.3	7.4	13.5	16.1	8.4
Heavy Fuel Oil	3.8	4.0	3.3	3.8	4.6	3.6	3.9	5.1	3.8
Aviation Gasoline	0.4	0.5	0.4	0.4	0.7	0.4	0.5	0.8	0.3
Propane	0.1	0.1	0.0	0.8	1.5	0.3	1.2	1.7	0.4
Electricity	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.5	0.0
Total[1]	100	—	—	100	—	—	100	—	—

[1] Do not necessarily add to 100 per cent as the high and low market shares often represent different Submittors.

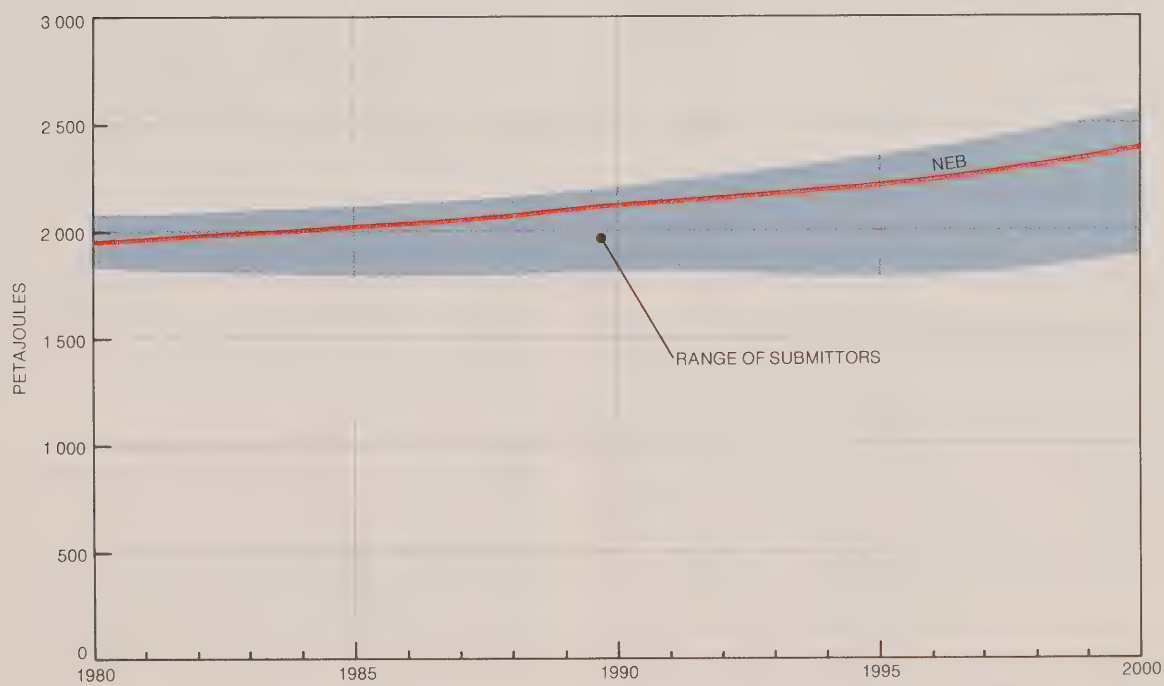

Figure 6-5 Energy Demand in the Transportation Sector Comparison of Forecasts

6.6.1 *Road Transportation*

Views of Submittors

Historically, motor gasoline and diesel have accounted for the entire demand for energy in road transportation. Submittors generally expected the dominant use of these two fuels to continue, although some Submittors anticipated substitution of gasoline by propane in commercial fleet operations. With the exception of Shell, Submittors did not foresee any role for electric power as a substitute fuel.

Those Submittors' forecasts of energy demand in road transportation that were undertaken on a total Canada basis are given in Table 6-22.

Table 6-22

TOTAL ENERGY DEMAND IN THE ROAD SECTOR - CANADA
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000	AAI-% 1980-2000
Gulf[1]	1 596	1 658	1 727	1 802	1 908	0.9
Imperial	1 670	1 673	1 643	1 615	1 556	–0.4
Norcen	1 507	1 510	1 522	1 454	1 531	0.1
Petro-Canada[1]	1 527	1 493	1 529	1 519	1 536	0.0
Shell[1]	1 461	1 353	1 314	—	1 358	–0.4
Texaco	1 490	1 454	1 542	1 495	1 600	0.4
NEB	1 564	1 584	1 632	1 670	1 748	0.6

(1) Supplemental Forecast
AAI—Average Annual Increase

Gulf projected the highest average annual rate of increase in demand, followed by Texaco and Norcen. Petro-Canada expected no growth in road transportation demand, while Imperial and Shell projected a decline at an average annual rate of 0.4 percent. Since Submittors' forecasts of average annual rates of change in total energy demand in road transportation are mainly a weighted average of their corresponding projections for motor gasoline and diesel, Table 6-23 gives, for each Submittor, estimated average annual rates of change in demand for the two fuels.

Submittors expected demand for motor gasoline to decline over the forecast period. Imperial and Shell, in particular, projected a significantly more rapid decline in gasoline demand than did other Submittors, particularly Gulf and Texaco.

In contrast with the demand for gasoline, Submittors forecast moderate to high rates of increase in road demand for diesel. The forecast average annual rates of growth in road consumption of diesel ranged from a high of 6.1 percent by Shell to a low of 3.3 percent by Imperial, with forecasts by Gulf and Texaco of 5.5 percent being close to the high forecast.

Table 6-23

ENERGY DEMAND IN THE ROAD SECTOR BY MAJOR COMPONENTS - CANADA
GROWTH RATES, 1980-2000
Comparison of Forecasts
(Percent per Annum)

	Motor Gasoline	Diesel	Total Road
Gulf[1]	–0.6	5.5	0.9
Imperial	–1.8	3.3	–0.4
Norcen	–0.7	4.8	0.1
Petro-Canada[1]	–0.8	3.6	0.0
Shell[1]	–3.0	6.1	–0.4
Texaco	–0.5	5.5	0.4
NEB	–0.9	5.2	0.6

(1) Supplemental Forecast

In regard to propane, Submittors generally assumed some displacement of motor gasoline by propane in taxis and delivery fleets. Imperial estimated demand for propane in road transportation to increase from almost no requirements in 1980 to 30 petajoules by 1990 and 37 petajoules by 2000. Imperial forecast conversion of 25 percent of the potential fleet market to propane in Ontario, Québec, British Columbia and Alberta by 1990. Gulf anticipated a more modest increase in propane demand, from two petajoules in 1980 to six petajoules in 1990 and nine petajoules in 2000.

In testimony, Shell projected propane demand in road transportation to increase to 5 petajoules in 1985, 22 petajoules in 1990, and 82 petajoules in 2000. Shell based the forecast on initiatives taken by the Ontario Government rather than those contained in the NEP. The forecast assumed that propane-fuelled vehicles would make up 7 percent of the new light truck fleet by 1990 and 15 percent by 2000. The estimated demand for propane was not, however, included in Shell's estimate of total energy demand in road transportation given in Tables 6-22 and 6-23. Petro-Canada's projection also assumed some substitution of propane for motor gasoline. The resulting demand for propane was not, however, quantified.

Shell alone anticipated the introduction of electric vehicles over the forecast period. Shell foresaw that by 1990, 0.6 percent of the car fleet and 0.3 percent of the truck fleet would use electric power instead of gasoline. These proportions were expected to increase to 2.7 percent and 1.3 percent, respectively, by the year 2000. The volumes of motor gasoline displaced by electric power were estimated to be equivalent to 5 petajoules in 1990 and 23 petajoules in 2000.

Submittors' evidence on the methodology and assumptions used to forecast demand for motor gasoline and diesel are described below.

Motor Gasoline

Submittors prepared separate estimates of demand for motor gasoline by automobiles and trucks. Evidence on demand for gasoline by automobiles is discussed first.

Imperial and Gulf projected demand for gasoline by cars using estimates of total distance travelled, coupled with forecasts of average new car fuel efficiencies.

Imperial's estimate of distance travelled by automobiles was based on its projection of the number of licensed drivers and its assumption regarding distance travelled per driver. The number of licensed drivers was forecast to increase from 13.7 million in 1980 to 19.6 million in the year 2000. Average annual kilometres per driver were assumed to increase from 11 500 kilometres in 1980 to 13 000 kilometres in 1990, thereafter they were expected to return to 1980 levels.

Gulf forecast distance travelled by automobiles using estimates of car registration and distance travelled per car. Registrations were projected to increase by two percent per year over the forecast period, while distance driven per car was anticipated to decline from 16 700 kilometres in 1980 to 16 000 kilometres in 2000.

Imperial expected greater improvements in car fuel efficiencies than did Gulf. Whereas Gulf forecast average new car fuel efficiencies to improve from 11.8 litres per 100 kilometres in 1980 to 8.6 litres per 100 kilometres in 1990, Imperial expected the efficiency to improve to 7.5 litres per 100 kilometres by 1990. These estimates compared with the voluntary average new car fuel efficiency standards of 11.8 litres per 100 kilometres in 1980 and 8.6 litres per 100 kilometres in 1985. Imperial also assumed that road fuel efficiencies would be 13 percent below those determined under controlled test conditions.

Petro-Canada, Shell and Texaco did not indicate the steps used to project automobile demand for gasoline. However, factors listed by these Submittors as affecting automobile gasoline consumption; shift to smaller cars, improvements in fuel efficiencies, substitution by diesel and to a limited extent by propane, were not basically different from those considered by Gulf and Imperial. There were, however, a few variations in details provided by these Submittors.

Petro-Canada, in addition to assuming some dieselization of automobiles, also expected introduction of compressed natural gas in urban fleet transportation. As noted above, Shell assumed some substitution of gasoline by electric power. Texaco predicted measures such as reduced speed limits and gasoline rationing.

Submittors considered economic activity and fuel costs to be the major determinants of demand for gasoline by trucks and buses. Their forecasts incorporated the allowance for factors such as dieselization and improvements in truck fuel efficiencies. Only Gulf and Shell provided separate estimates of the gasoline demand by trucks and buses. While Gulf expected gasoline demand by trucks and buses to increase at an average annual rate of 2 percent, Shell estimated it to decline at a rate of 2.2 percent per year over the forecast period.

British Columbia, Manitoba, New Brunswick, Newfoundland, Nova Scotia and Ontario submitted forecasts of motor gasoline demand in their respective provinces. British Columbia's forecast covered the period up to 1995, while New Brunswick's estimates covered the period up to 1985.

British Columbia and Newfoundland estimated demand for gasoline to increase at average annual rates of 2.2 and 2 percent, respectively. In contrast, Manitoba, Nova Scotia and Ontario predicted declines at average annual rates of 1.7, 0.1 and 0.2 percent, respectively. New Brunswick expected demand for gasoline to remain constant throughout its forecast period.

British Columbia's forecast was based on the expectation that fuel requirements of vehicles other than passenger cars would continue to increase, while fuel demand by passenger cars would stabilize after 1986 because of improvements in fuel efficiencies.

Manitoba estimated lower vehicle utilization, a shift to smaller vehicles and improvements in fuel efficiencies.

Nova Scotia assumed annual distance driven per driver to decline from 18 400 kilometres in 1978 to 16 000 kilometres by 2000.

Ontario assumed achievement of the 1985 model year target of 8.6 litres per 100 kilometres and further expected average fuel economy to improve to 7.8 litres per 100 kilometres by 2000.

The share of diesel cars in new car sales was forecast by Ontario to increase from 2 percent in 1978 to 8.5 percent by 1995 after which it would remain unchanged. Ontario also expected considerable substitution of gasoline by propane and electricity.

Road Diesel

Trucks account for the major proportion of demand for diesel in road transportation. Shell estimated the current share of trucks and buses in total road diesel use to be 98 percent.

Submittors estimated demand for diesel in the road sector based on forecasts of economic activity, coupled with the expectation that rising fuel costs would lead to increased dieselization of both passenger cars and commercial trucking.

Gulf estimated the proportion of cars on the road which will be diesel-powered to be six percent in 1990 and ten percent in 2000. This was expected to result in an average annual rate of growth of 8.3 percent in demand for diesel by cars in the 1990s.

Gulf also expected increased dieselization of commercial trucks. As a consequence, the proportion of diesel in total fuel demand, gasoline plus diesel, by commercial trucks was forecast to increase from 50 percent in 1980 to 79 percent by 2000.

While Shell foresaw significant substitution of diesel for gasoline in the car and in the light and medium truck markets, no estimates were provided. Imperial and Texaco submitted projections of diesel penetration in the car market. Imperial anticipated ten percent of new car sales to be diesel-powered during the

period 1985-2000. Texaco predicted the market share of diesel cars in new car sales to increase from 3.2 percent in 1985 to 13.5 percent in 2000.

With respect to forecasts of demand for road diesel by provincial governments, Submittors with the exception of Manitoba expected demand to increase over the forecast period. The forecast annual rates of growth ranged from a high of 7.7 percent by Newfoundland to a low of 2.5 percent by Nova Scotia, with British Columbia and Ontario estimating rates of growth to be 4.5 percent and 3.9 percent, respectively. Manitoba expected road demand for diesel to decline at an average annual rate of 0.6 percent.

Gulf, Petro-Canada and Shell reduced their forecasts of total energy demand in road transportation subsequent to the announcement of the NEP as shown in Table 6-24.

Table 6-24

ROAD TRANSPORTATION: SUPPLEMENTAL FORECAST RELATIVE TO THE ORIGINAL FORECAST

Percent Increase (+) or Decrease (–)

	Motor Gasoline (%)		Road Diesel (%)		Total Road (%)	
Submittor	1990	2000	1990	2000	1990	2000
Gulf	–12	–21	+36	+44	–2	–5
Petro-Canada	– 6	– 6	–23	–33	–10	–15
Shell	–17	–35	0.0	0.0	–12	–21

All three Submittors expected a lower demand for motor gasoline. A principal reason was the prediction that fuel efficiencies would be higher than originally assumed, especially after 1985. In addition, Gulf anticipated reduced distance per car and increased substitution of diesel for gasoline in cars and trucks. Shell predicted increased substitution of propane and electric power for gasoline.

The post-NEP demand estimates for road diesel presented a mixed pattern. Whereas Gulf increased its pre-NEP forecast of demand for diesel by 36 percent and 44 percent, respectively, in 1990 and 2000, Petro-Canada reduced its forecast by 23 percent and 33 percent, respectively. The different patterns reflected varying perceptions of the effects of the NEP on fuel substitution. While Gulf expected increased dieselization of cars and trucks, Petro-Canada predicted a less rapid conversion from gasoline to diesel, displacement of diesel by compressed natural gas and increased conservation due to higher diesel prices.

Views of the Board

The Board forecasts total energy demand in road transportation to increase from 1 564 petajoules in 1980 to 1 748 petajoules in 2000 as shown in Table 6-25. This represents an average annual growth rate of 0.6 percent, which is higher than that forecast by all Submittors except Gulf. The Board's higher estimate is due mainly to its higher forecast growth in road demand for diesel and to a lesser extent for propane. The Board's forecast is compared to the Submittors' forecasts in Figure 6-6.

The Board expects a faster decline in the demand for motor gasoline, than all Submittors except Imperial and Shell. The estimates of Imperial and Shell show both an accelerated decline in gasoline demand and a decrease in total demand for energy in the road transportation sector. Compared with the Board, Gulf estimated not only a slower rate of decline in demand for motor gasoline but also a faster rate of growth in road demand for diesel.

The Board does not foresee any significant role in the road sector for electric power over the forecast period. The same is true for new fuels such as methanol, ethanol and compressed natural gas.

The following subsections deal, respectively, with motor gasoline, road diesel, propane and electric power.

Motor Gasoline

The Board has adopted the Statistics Canada definition of motor gasoline which includes road uses of gasoline and also non-road uses such as tractors and fork lifts. These non-road uses, however account for only five to six percent of the total demand for motor gasoline.

The Board's forecast of total energy demand in road transportation is based upon fuel prices estimated using blended prices forecast in the NEP. Unlike the Board's previous forecast, the current forecast expects substitution of propane for gasoline consistent with the policy specified in the NEP.

The Board forecasts the demand for motor gasoline in road transportation to decline from 1 341 petajoules in 1980 to 1 115 petajoules in 2000, an average annual decrease of 0.9 percent.

The Board's forecast of total demand for gasoline is the sum of demand by passenger automobiles, estimated using a passenger car gasoline model, and demand by non-automobile vehicles, mainly trucks, estimated from an equation relating such demand to real domestic product, gasoline price and last year's demand. The passenger car model estimates demand for motor gasoline by passenger automobiles by, first, forecasting urban and rural distances travelled by large and small cars and then applying estimates of appropriate fuel economies. The model involves estimation of new car sales by size, scrappage rates, annual distances travelled and fuel economies. The resulting forecast of total demand for motor gasoline is adjusted to reflect the Board's estimates of substitution of gasoline by diesel and propane.

The Board's forecast shows a much slower rate of decline in total demand for gasoline than does Shell mainly because of the Board's lower expectations of substitution by diesel and propane and of no penetration by electric power in the gasoline market. Imperial's forecast of a faster average annual rate of reduction in demand for gasoline compared to the Board's estimates is explained primarily by Imperial's higher estimates of automobile fuel efficiencies and to a lesser degree by its slightly higher expected substitution of gasoline by diesel and propane. In contrast, the slower rate of decline in gasoline demand projected by Gulf vis-à-vis the Board traces partly to Gulf's lower

Table 6-25

DEMAND IN THE ROAD SECTOR BY ENERGY FORM - CANADA
Comparison of Forecasts
(Petajoules)

Energy Form	1980			1990			2000		
	NEB	Submittors		NEB	Submittors		NEB	Submittors	
		High	Low		High	Low		High	Low
Motor Gasoline	1 341	1 379	1 249	1 212	1 330	916	1 115	1 375	674
Diesel	221	292	129	403	450	195	605	688	329
Propane	2	2	0	17	31	6	28	37	9
Electricity	0	2	0	0	3	0	0	13	0
Total[1]	1 564	1 670	1 461	1 632	1 727	1 314	1 748	1 908	1 358

[1] Not necessarily the sum of the above energy forms, since high and low demands for particular energy forms often represent different Submittors.

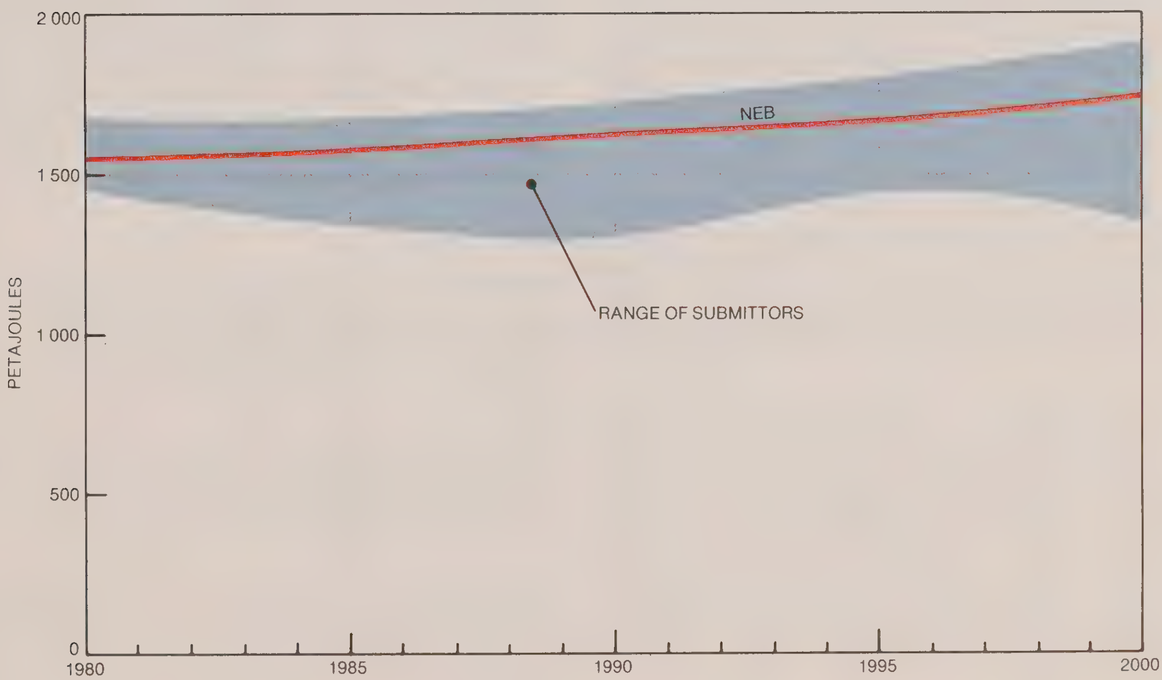

Figure 6-6 Energy Demand in the Road Sector
Comparison of Forecasts

estimate of substitution by diesel and propane in the gasoline market, partly to its higher forecast of demand for gasoline by trucks and buses and partly to its prediction of a slower rate of decline in distance travelled compared to the Board's estimate. Texaco's prediction of a slower rate of decline in gasoline demand relative to the Board's projection is explained mainly by Texaco's lower prediction of dieselization combined with its assumption of no penetration by propane in the gasoline market.

The Board expects that mainly as a result of rising gasoline prices and a gradual saturation of car ownership, there will be a substantial reduction in the average annual rate of growth in new car sales, compared to the historical period. The Board projects new car sales to increase at an average annual rate of two percent over the period from 1979 to 2000 compared with the historical rate of 5.1 percent during 1970-79. The number of cars on the road is projected to increase at two percent per year over the forecast period compared with 4.7 percent during 1970-79. This forecast is close to that of Gulf. Annual distance travelled per car is estimated by the Board to decline gradually from the current 15 456 kilometres to 14 764 kilometres by 2000. This decline is more rapid than estimated by Gulf and Imperial.

Consistent with Submittors' forecasts, the Board anticipates the recent trend towards purchase of smaller fuel efficient cars to continue over the forecast period. In the Board's opinion, the trend will be reinforced by rising gasoline prices, the growth in the proportion of women in the labour force, improvements in the fuel efficiencies of North American intermediate and compact cars to make them competitive with imports, and competitive pricing of small models to induce families already owning a car to buy a second car. The Board estimates that these factors will increase the market share of small cars in total new car sales for Canada as a whole from 50 percent in 1980 to 63 percent by 1995, after which it will remain stable until 2000.

While Submittors did not provide estimates of market shares of small and large cars, a comparison of Submittors' estimates of average new car fuel efficiencies with those of the Board implies that the Board's forecast of market shares is not out of line with comparable projections implicit in Submittors' gasoline forecasts.

The Board's estimates of fuel efficiencies of new small and large cars, shown in Table 6-26, are based on an analysis of recent trends and announced plans of automobile manufacturers. Average new car fuel efficiencies under road conditions are forecast by the Board to improve from 12.7 litres per 100 kilometres in 1980 to 9.3 litres per 100 kilometres in 1985 and 8.1 litres per 100 kilometres in 1990. The forecast average fuel efficiency in 1990 is almost identical with Shell's estimate of 8 litres per 100 kilometres, is six percent higher than Gulf's but seven percent lower than Imperial's.

The gradual substitution of the existing stock of cars by more fuel-efficient automobiles exercises a progressively dampening effect on gasoline demand by increasing the average fuel efficiency of the vehicle stock. The Board expects that general fuel efficiency improvements of all car sizes, combined with a shift to down-sized models, would increase average fleet fuel efficiency from 15.6 litres per 100 kilometres in 1980 to 10.4 litres per 100 kilometres in 1990. The Board's estimate of fleet fuel efficiency in 1990 is almost identical with Texaco's, and three to four percent lower than those forecast by Gulf and Imperial.

Table 6-26

NEW CAR FUEL ECONOMIES BY SIZE
NEB Estimates
(Litres per 100 Kilometres)

	Small Cars		Large Cars	
Year	City	Other	City	Other
1980	11.8	9.2	17.5	13.8
1985	8.6	6.7	13.5	10.6
1990	7.7	6.0	12.0	9.4
2000	7.7	6.0	12.0	9.4

The Board, like the Submittors, expects increasing penetration by diesel-powered vehicles in the gasoline market. The Board estimates the proportion of diesel-powered automobiles and trucks in total new vehicle sales to increase from six percent in 1985 to ten percent in 1990 and 13 percent in 2000.

Regarding demand for gasoline by trucks and buses, the Board's forecast is based on estimates of real domestic product, fuel prices and expected conservation due to improvements in fuel efficiencies. The Board estimates truck and bus consumption of gasoline to increase at an average annual rate of 0.3 percent over the forecast period. This rate of growth in gasoline demand is much lower than Gulf's estimate of two percent but higher than Shell's. Shell estimated truck and bus gasoline demand to decline at an average annual rate of 2.2 percent over the forecast period.

Road Diesel

The Board forecasts the demand for road diesel to increase from 221 petajoules in 1980 to 605 petajoules in 2000. This represents an average annual rate of growth of 5.2 percent, compared with the 16.5 percent annual growth rate experienced over the historical period 1970-79.

The Board projects road consumption of diesel on the basis of estimates of real domestic product, anticipated substitution of diesel for gasoline in automobiles and trucks, and conservation in response to higher expected diesel prices.

Diesel is used for motive power mainly by trucks involved in intercity movement of goods. Growth in inter-city movement of goods is expected as a result of the forecast increase in real domestic product. Diesel trucks weigh at least 8.6 tonnes, and generally more than 12 tonnes and travel, on average, 71 000 kilometres per year. Though diesel engines are, in general, more fuel efficient than gasoline engines, the sheer weight of trucks and the goods they carry makes it difficult for diesel trucks to

achieve fuel economies higher than between 53 litres per 100 kilometres and 49 litres per 100 kilometres. The Board, therefore, does not expect significant improvements in these fuel efficiencies. However, the Board estimates that improvements in payload efficiencies and other measures will reduce demand for diesel fuel by ten percent by the year 2000.

Historically, there has been a decline in the number of gasoline-powered trucks weighing more than 12 tonnes and a corresponding increase in the number of diesel-powered trucks. The proportion of gasoline-powered trucks of the total number of trucks weighing more than 12 tonnes declined from 74 percent in 1970 to only 18 percent in 1978. The Board expects this trend to continue over the forecast period. Additionally, as noted previously, the Board anticipates an increase in proportions of diesel-powered automobiles and trucks in lower weight classes in total vehicle sales.

Since the Board forecasts demand for gasoline to decline, the expected growth in road demand for diesel results in a significant increase in the share of diesel in total energy demand in road transportation. The share of diesel is estimated to increase from 14 percent in 1980 to 25 percent in 1990 and to 35 percent in the year 2000, as shown in Table 6-27.

The Board's higher estimate of growth in road consumption of diesel contributes to the higher estimate of growth in total energy demand in road transportation relative to forecasts of Norcen and Petro-Canada.

Propane

The Board's forecast of demand for propane in road transportation is dependent upon a price advantage for propane and active efforts by all levels of government to promote its use, particularly in commercial fleets. The Board notes that measures such as a taxable grant of $400 per commercial fleet vehicle converted to propane, announced in the NEP, and removal of sales taxes on propane-powered vehicles and propane, adopted by Ontario, should encourage the use of propane.

The Board agrees with Submittors that high costs of conversion would rule out any significant conversions to propane of private automobiles and small fleets. The Board expects government fleets and commercial fleets with more than 20 vehicles to account for most of the displacement of gasoline by propane. The number of propane-powered vehicles in government fleets is estimated to increase from 170 in 1980 to about 25 000 by 2000. The number of propane-fuelled vehicles in commercial fleets is projected to increase from about 8 600 in 1980 to 120 000 in 2000. These estimates of conversion to propane are higher than those of Submittors except Imperial and Shell. Thus, whereas the Board estimates road demand for propane to increase from 2 petajoules in 1980 to 28 petajoules in the year 2000, Imperial and Shell forecast the demands to be 37 petajoules and 82 petajoules, respectively, in 2000.

The Board's forecast of average annual rate of growth in total energy demand in road transportation is higher than Texaco's primarily because of the Board's higher estimate of growth in road demand for propane.

Electric Power

The Board is of the opinion that substantial technical improvements, especially in energy storage batteries, are required before electric cars can successfully penetrate the vehicle market. Because of uncertainties concerning such technological developments and the small expected impact they would have on energy demand even by the year 2000, the Board's forecast contains no specific allowance for energy use by electric cars. This procedure is in conformity with that adopted by most Submittors.

Table 6-27

DEMAND IN THE ROAD SECTOR BY ENERGY FORM - CANADA
MARKET SHARES
Comparison of Forecasts
(Percent)

Energy Form	1980			1990			2000		
	NEB	Submittors		NEB	Submittors		NEB	Submittors	
		High	Low		High	Low		High	Low
Motor Gasoline	85.8	91.4	82.6	74.3	87.2	69.7	63.8	78.5	49.6
Diesel	14.1	17.4	8.6	24.7	30.3	12.8	34.6	50.4	21.5
Propane	0.1	0.1	0.0	1.0	1.8	0.3	1.6	2.4	0.5
Electricity	0.0	0.1	0.0	0.0	0.2	0.0	0.0	0.7	0.0
Total(1)	100	—	—	100	—	—	100	—	—

(1) Do not necessarily add to 100 per cent as the high and low market shares often represent different Submittors.

6.6.2 *Rail Transportation*

Views of Submittors

Forecasts of total Canadian demand for energy in the rail sector were provided by Gulf, Imperial, Petro-Canada, Shell, Texaco, and Norcen.

Forecasts of Submittors differed widely not only in levels of demand projected for future years, but also in estimates given for the base year. Those Submittors whose forecasts of energy demand were in the high end of the range included the demand for heavy fuel oil and coal which are used to heat stations and other supporting facilities. For the year 1980, estimates ranged from 95 petajoules by Gulf to 122 petajoules by Petro-Canada, and for the year 2000, they ranged from 110 petajoules by Imperial to 186 petajoules by Petro-Canada. Table 6-28 compares the Submittors' forecasts.

Table 6-28

TOTAL ENERGY DEMAND IN THE RAIL SECTOR - CANADA
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000	AAI-% 1980-2000
Gulf[1]	95	99	103	113	123	1.3
Imperial	99	105	106	109	110	0.5
Norcen	121	131	142	157	172	1.8
Petro-Canada[1]	122	133	148	168	186	2.1
Shell[1]	102	125	143	163	183	3.0
Texaco	120	135	144	159	175	1.9
NEB	107	115	126	139	152	1.8

(1) Supplemental Forecasts
AAI - Average Annual Increase

Imperial, which predicted the lowest average rate of growth in rail transportation energy demand of 0.5 percent per year, assumed that improvements in efficiency would largely offset any increased requirements arising from growth in freight movements. On the other hand, Shell, with the highest average expected rate of growth of 3.0 percent per year, projected similar economic conditions to Imperial but assumed no efficiency gains. The remaining Submittors expected modest rates of growth in energy demand in the range of 1.3 percent to 2.1 percent per year.

All Submittors, except Texaco and Petro-Canada, indicated that oil products would be the only source of energy in the rail sector. Texaco and Petro-Canada expected limited use of coal, decreasing from about one petajoule in 1980 to zero by the year 2000.

Some of the Submittors assigned all of the oil demand to diesel fuel oil; while the others allocated about 96 percent of the market to diesel fuel and the balance to heavy fuel oil.

The Government of British Columbia stated that although measures such as better grading could serve to reduce rail transport energy requirements, it preferred to make no allowance for such improvements. Of the remaining Submittors, only Imperial incorporated conservation of energy resulting from efficiency improvements in the rail sector.

Both British Columbia and Texaco considered introduction of electrification of the rail system unlikely since they believed that no company was actively investigating this form of conversion. In addition, British Columbia believed that the capital costs of electrification would be prohibitive.

Following the announcement of the NEP, Gulf, Shell, and Petro-Canada presented revised forecasts of energy demand in the rail sector. It was generally stated that the NEP had little or no effect on their projections of energy demand since a switch from truck to rail mode was not expected. British Columbia did not submit a revised forecast but indicated that in the light of higher expected prices of diesel, it might reassess the potential for coal as a source of energy in the rail sector.

Views of the Board

Total energy requirements for rail transportation are forecast by the Board to grow at an average annual rate of 1.8 percent from 107 petajoules in 1980 to 152 petajoules in 2000. This projection is based on forecast total real domestic product in the manufacturing, agriculture and mining sectors. The bulk of goods transported by rail are the products of these sectors. Tables 6-28 and 6-29 and Figure 6-7 compare the Board's forecast of energy requirements in rail transportation with those of the Submittors.

The Board expects diesel fuel oil to be the dominant fuel consumed in rail transportation. Coal use by railways for non-motive purposes has been reclassified to the commercial sector by Statistics Canada.

Although the Board recognizes that electrification of the railways would contribute to savings in oil consumption, the considerable cost involved is likely to prevent rail companies from converting during the forecast period. The Board is, however, aware of a major rail company currently investigating a method of electrifying steep grades in the Rockies and the Selkirks, with the aim of reducing fuel consumption and improving energy efficiency. Since the Board has not assumed the use of electricity as a viable alternative to diesel fuel oil during the forecast period, it foresees limited opportunity for energy conservation in rail transportation despite expected increases in diesel fuel prices. The Board expects rail companies to undertake structural improvements of rail tracks resulting in forecast demand for 1985 that is five percent lower than what it would have been without such improvements. This saving is expected to rise to ten percent by the year 2000.

Table 6-29

DEMAND IN THE RAIL SECTOR BY ENERGY FORM - CANADA
Comparison of Forecasts
(Petajoules)

Energy Form	1980 NEB	1980 Submittors High	1980 Submittors Low	1990 NEB	1990 Submittors High	1990 Submittors Low	2000 NEB	2000 Submittors High	2000 Submittors Low
Oil									
Diesel Fuel	107	116	95	126	143	103	152	183	110
HFO	0	5	0	0	7	0	0	9	0
Coal	0	1	0	0	0	0	0	0	0
TOTAL(1)	107	122	95	126	148	103	152	186	110

(1) Not necessarily the sum of the above energy forms as the high and low demand for particular energy forms often represent different Submittors.

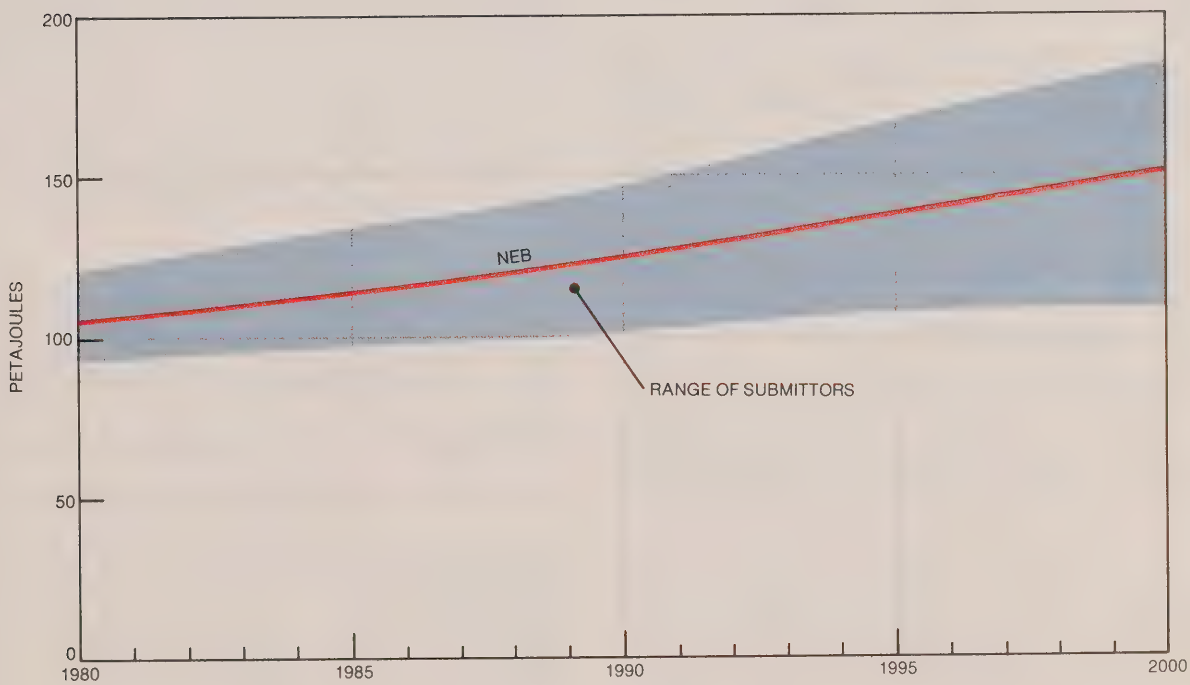

Figure 6-7 Energy Demand in the Rail Transportation Sector
Comparaison of Forecasts

6.6.3 *Air Transportation*

Views of Submittors

Forecasts of total demand for energy for air transportation were provided by Dome, Gulf, Imperial, Norcen, Petro-Canada and Texaco.

Most Submittors based their forecasts on the expected demand for air transportation services and the potential to conserve energy in the sector. They indicated that they expected an increasing preference for air travel as a result of rising economic activity, as well as the availability of incentive airfares. They also felt conservation measures would be induced by increases in real energy prices.

All of the Submittors projected average annual growth rates lower than the historical rate of approximately 5.2 percent between 1970 and 1980. These annual growth rates ranged from the lowest estimate of 0.4 percent by Norcen to the highest estimate of 3.6 percent by Petro-Canada, for the period 1980 to 2000. Gulf, Imperial, Shell, and Petro-Canada forecasted air sector energy demand to increase at average annual rates in a narrow range of 3.4 percent to 3.6 percent during the period 1980 to 2000. Dome, Texaco, and Norcen projected lower annual growth rates of 2.4 percent, 1.4 percent and 0.4 percent, respectively.

Almost all Submittors expected positive growth in energy demand throughout the forecast period. Excluding Imperial, there was general agreement that the growth in energy demand would be somewhat higher in the latter half of the forecast period. Table 6-30 compares the forecasts and the expected annual growth rates for the period 1980 through 2000.

Both Norcen and Texaco projected little or no growth up to 1995 followed by a dramatic increase in the remaining five years. Texaco indicated that this pattern of growth reflected the assumption of increased efficiencies of a new stock of aircraft offsetting the impact of an increasing population during the 1980 to 1995 period. Later when less turn-over in aircraft stock is expected, a dramatic increase in jet fuel demand would occur.

Table 6-30

TOTAL ENERGY DEMAND IN THE AIR SECTOR - CANADA
Comparison of Forecasts
(Petajoules)

Submittors	1980	1985	1990	1995	2000	AAI-% 1980-2000
Dome	158	173	201	230	253	2.4
Gulf[1]	177	206	239	293	355	3.5
Imperial	184	218	263	318	357	3.4
Norcen	162	163	149	148	176	0.4
Petro-Canada[1]	177	197	223	275	359	3.6
Shell[1]	172	199	238	285	343	3.5
Texaco	161	166	166	173	211	1.4
NEB	175	206	235	269	332	3.3

[1]Supplemental Forecasts
AAI - Average Annual Increase

The Governments of British Columbia, Ontario, Manitoba, Nova Scotia, Newfoundland, and New Brunswick provided forecasts of energy demand for their respective provinces. Although they had varying outlooks, most forecasts reflected lower growth rates than those experienced in the past as shown in Table 6-31.

Newfoundland, Nova Scotia, and Ontario expected modest growth of about 3.0 percent annually. New Brunswick projected no growth. British Columbia and Manitoba projected average annual growth rates of 3.8 percent and 1.9 percent, respectively.

Information was provided by Gulf, Shell, Imperial, Texaco, and the Governments of Ontario and British Columbia with regard to conservation in the air transportation sector. It was generally agreed that rising fuel costs would stimulate measures to conserve energy in this sector. These measures would include increased load factors, percentage of total available seats which are occupied, route rationalization and the use of more wide-bodied fuel-efficient aircraft. However, only British Columbia indicated the extent to which its forecast of demand reflected the effects of savings due to energy conservation.

British Columbia assumed increases in load factors for its medium and long haul domestic flights of 3.5 percent by 1981 and of a further 3.5 percent by 1986, all from the 1979 base. For short haul domestic flights, load factors were assumed to increase by five percent in 1981 and by a further five percent and ten percent by 1986 and 1996, respectively. Energy savings of ten percent by 1986 and a further ten percent by 1991 were also expected as a result of the shift to more energy efficient aircraft.

Following the announcement of the NEP, Gulf and Petro-Canada revised their forecasts of energy demand for the air sector. Gulf and Petro-Canada had previously forecast annual average growth rates that differed significantly; 3.1 percent and 4.5

Table 6-31

TOTAL ENERGY DEMAND IN THE AIR SECTOR - BY PROVINCE
Provincial Governments' Forecasts

Provincial Governments	Average Annual Increase, %		
	1970-1980 Actual	1975-1980 Actual	1980-2000 Forecast
Newfoundland	—	5.1	3.0
New Brunswick	—	3.9	0.0[1]
Nova Scotia	—	–0.5	2.8
Ontario	6.2	4.3	2.9
Manitoba	2.8	2.0	1.9
British Columbia	7.9	6.0	3.8[2]

[1] Forecast Period, 1979-1985
[2] Forecast Period, 1980-1996

Table 6-32

DEMAND IN THE AIR SECTOR BY ENERGY FORM - CANADA
Comparison of Forecasts
(Petajoules)

Energy Form	1980			1990			2000		
	NEB	Submittors		NEB	Submittors		NEB	Submittors	
		High	Low		High	Low		High	Low
Oil									
Aviation Turbo	167	176	150	226	254	142	321	350	169
Aviation Gasoline	8	9	8	9	13	7	11	17	7

Table 6-33

DEMAND IN THE AIR SECTOR BY ENERGY FORM - CANADA
MARKET SHARES
Comparison of Forecasts
(Percent)

Energy Form	1980			1990			2000		
	NEB	Submittors		NEB	Submittors		NEB	Submittors	
		High	Low		High	Low		High	Low
Oil									
Aviation Turbo	95.3	95.7	94.4	96.2	96.5	94.4	96.7	97.4	95.0
Aviation Gasoline	4.7	5.6	4.3	3.8	5.6	3.5	3.3	5.0	2.6

percent respectively. After taking into account provisions contained in the NEP, they forecast growth rates that were virtually the same; 3.5 percent and 3.6 percent respectively. Shell, which had forecast an annual rate of growth of 3.5 percent prior to the NEP, indicated no change to its forecast of energy demand in the air sector in its supplemental submission.

Views of the Board

The Board forecasts energy demand in the air sector to grow at the average annual rate of 3.3 percent from 175 petajoules in 1980 to 332 petajoules in 2000. Oil is expected to account for all of the energy consumed in this sector. Consumption of aviation turbo fuel, the principal fuel used, is expected to account for practically all of the growth in demand. In contrast, aviation gasoline requirements are expected to remain relatively constant. The Board's forecast is compared with those of the Submittors in Tables 6-32 and 6-33 and Figure 6-8.

Rising energy demand in this sector reflects a forecast of continued growth in passenger air travel stimulated by rising economic activity. Nonetheless, the projected rate of increase is below historical levels because airlines are expected to undertake conservation measures to moderate their energy requirements. The lack of growth in aviation gasoline demand reflects the expectation that piston-type aircraft will continue to be replaced by turbo aircraft.

The Board estimates that conservation measures in the air sector will result in forecast demand for 1985 that is ten percent lower than what it would be in the absence of such measures. This conservation saving is expected to rise to 15 percent by the year 2000. These conservation savings will be induced by price increases for aviation fuels. Expected conservation measures include improvements in aircraft efficiency, as well as in the operating efficiency of the air transportation system.

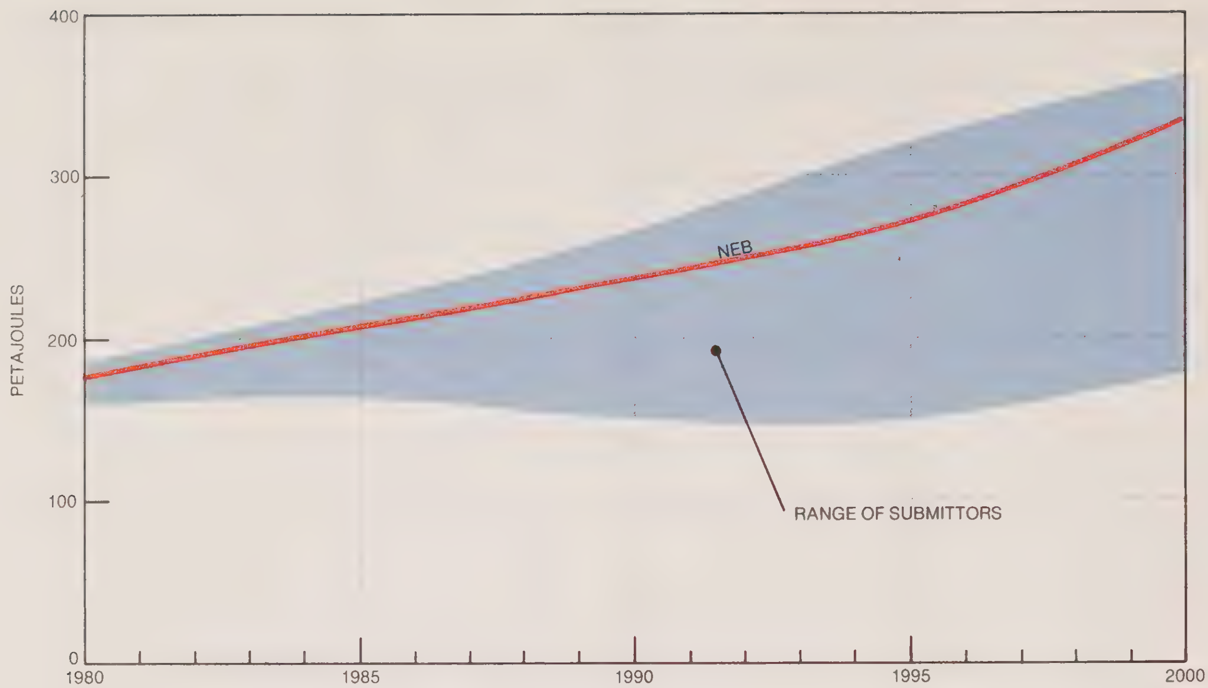

Figure 6-8 Energy Demand in the Air Transportation Sector
Comparison of Forecasts

6.6.4 *Marine Transportation*

Views of Submittors

Expected annual rates of growth over the forecast period, 1980 to 2000, in total energy demand in the marine sector ranged from 0.4 percent by Imperial to 2.6 percent by Shell. Table 6-34 compares the Submittors' projections.

All Submittors based their forecasts of energy demand on projections of economic activity and real energy prices. An additional consideration by Imperial and British Columbia was the competitive position of heavy fuel oil at Canadian ports relative to European ports. They assumed that, as a result of the competitive advantage of foreign heavy fuel oil, international shipping would continue to prefer to obtain fuel elsewhere, rather than in Canada.

For the Atlantic ports in particular, the projections of energy demand by most Submittors seemed to suggest a less competitive position for Canadian heavy fuel oil than that experienced in 1979. Texaco and the Government of New Brunswick differed from this view with forecasts that indicated a continuation of the bunker fuel demand reached in the Atlantic provinces in 1979, when heavy fuel oil in Canada was priced below the European price.

All Submittors expected diesel fuel oil and heavy fuel oil to provide all of the energy consumed in the marine sector. Tables 6-35 and 6-36 show the range of expected levels and market shares for diesel and heavy fuel oil. Most Submittors projected a declining market share for heavy fuel oil although it was expected to continue to be a major source of energy.

Only Gulf, Shell and Petro-Canada provided revised forecasts of energy demand following the announcement of the NEP. Whereas Gulf and Shell expected no impact on demand, Petro-Canada expected the average annual rate of growth in demand to be 1.6 percent from 1980 to 2000, a decline from their pre-NEP forecast growth rate of 1.8 percent.

Table 6-34

TOTAL ENERGY DEMAND IN THE MARINE SECTOR - CANADA
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000	AAI-% 1980-2000
Gulf[1]	113	119	127	141	156	1.6
Imperial	117	118	121	122	126	0.4
Norcen	109	115	119	123	133	1.0
Petro-Canada[1]	109	113	125	135	149	1.6
Shell[1]	100	115	131	148	166	2.6
Texaco	106	115	123	129	142	1.5
NEB	112	118	128	139	153	1.6

[1] Supplemental Forecast
AAI - Average Annual Increase

Views of the Board

Energy demand for marine transportation is forecast by the Board to grow at the average annual rate of 1.6 percent from 112 petajoules in 1980 to 153 petajoules in 2000. Tables 6-34 to 6-36 and Figure 6-9 compare the Board's forecast with those of the Submittors.

The Board based its forecast of energy demand on expected levels of sea cargo activity and the prices of marine diesel and heavy fuel oil. Activity is assumed to depend on the level of output in the manufacturing, agriculture and mining industries. Strong growth in these industries is projected during the forecast period. The Board expects increasing marine fuel prices over the forecast period.

In light of higher prices for marine fuels, the Board expects shipping companies to adopt fuel conservation measures such as improved operating practices and reduced turnaround time at ports. The Board has assumed that marine transportation energy demand will be less by 5 percent in 1980, 10 percent in 1985, and 15 percent in the year 2000, than it would be in those years if conservation measures were not implemented.

The Board expects that only oil will be used for marine transportation during the forecast period. Marine diesel requirements are projected to grow faster than those for heavy fuel oil.

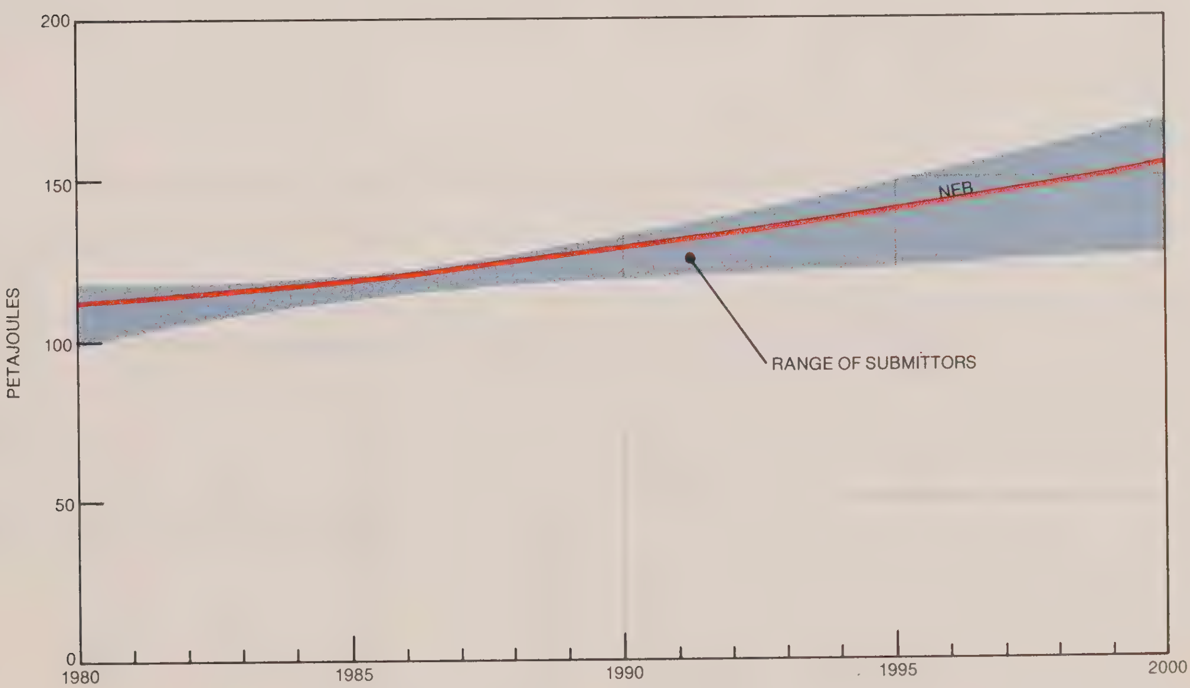

Figure 6-9 Energy Demand in the Marine Transportation Sector
Comparison of Forecasts

Table 6-35

DEMAND IN THE MARINE SECTOR BY ENERGY FORM - CANADA
Comparison of Forecasts
(Petajoules)

Energy Form	1980			1990			2000		
	NEB	Submittors		NEB	Submittors		NEB	Submittors	
		High	Low		High	Low		High	Low
Oil									
Diesel Fuel	39	43	37	47	57	44	59	77	45
Heavy Fuel	73	74	61	81	80	73	94	99	79

Table 6-36

DEMAND IN THE MARINE SECTOR BY ENERGY FORM - CANADA
MARKET SHARES
Comparison of Forecasts
(Percent)

Energy Form	1980			1990			2000		
	NEB	Submittors		NEB	Submittors		NEB	Submittors	
		High	Low		High	Low		High	Low
Oil									
Diesel Fuel	34.8	39.3	34.7	36.7	43.2	36.4	38.6	46.2	35.2
Heavy Fuel	65.2	65.3	60.6	63.3	63.6	56.8	61.4	64.8	53.8

6.7 Other Non-Energy Uses

Views of Submittors

Those non-energy uses of petroleum products, other than petrochemical feedstocks, forecast by Submittors were the demand for asphalt, lubricating oils and greases, naphtha specialties, petroleum coke and other products. For the year 1980, Submittors estimated that asphalt accounted for approximately 60 percent of total demand, lubes and greases about 17 percent, and other products about 23 percent.

Table 6-37 and Figure 6-10 compare the Submittors' forecasts of other non-energy uses with that of the Board for total Canada. Dome projected the lowest growth rate over the forecast period of 1.3 percent per year, while Petro-Canada projected the highest growth rate of 3.0 percent per year.

With regard to the projected demand for individual products in this category, Submittors expected that the greatest annual growth rates over the entire forecast period would be experienced by asphalt, with estimates ranging between 1.2 and 3.4 percent, and by lubes and greases, with estimates ranging between 2.6 and 3.2 percent. Demand for other products was estimated, on average, to increase at about 1.2 percent per year.

Table 6-37

TOTAL DEMAND FOR OTHER NON-ENERGY USES - CANADA
(Excluding Petrochemical Feedstocks)
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000	AAI-% 1980-2000
Dome	265	273	288	312	344	1.3
Gulf(1)	238	276	318	362	407	2.7
Imperial	240	276	317	365	423	2.9
Petro-Canada(2)	224	265	307	359	404	3.0
Shell(1)	235	261	285	308	333	1.8
Texaco(1)	264	308	362	417	466	2.9
NEB	259	295	336	382	438	2.7

(1) Supplemental Forecast
(2) Pre-NEP forecast, since supplemental forecast did not provide complete data for this category.
AAI - Average Annual Increase

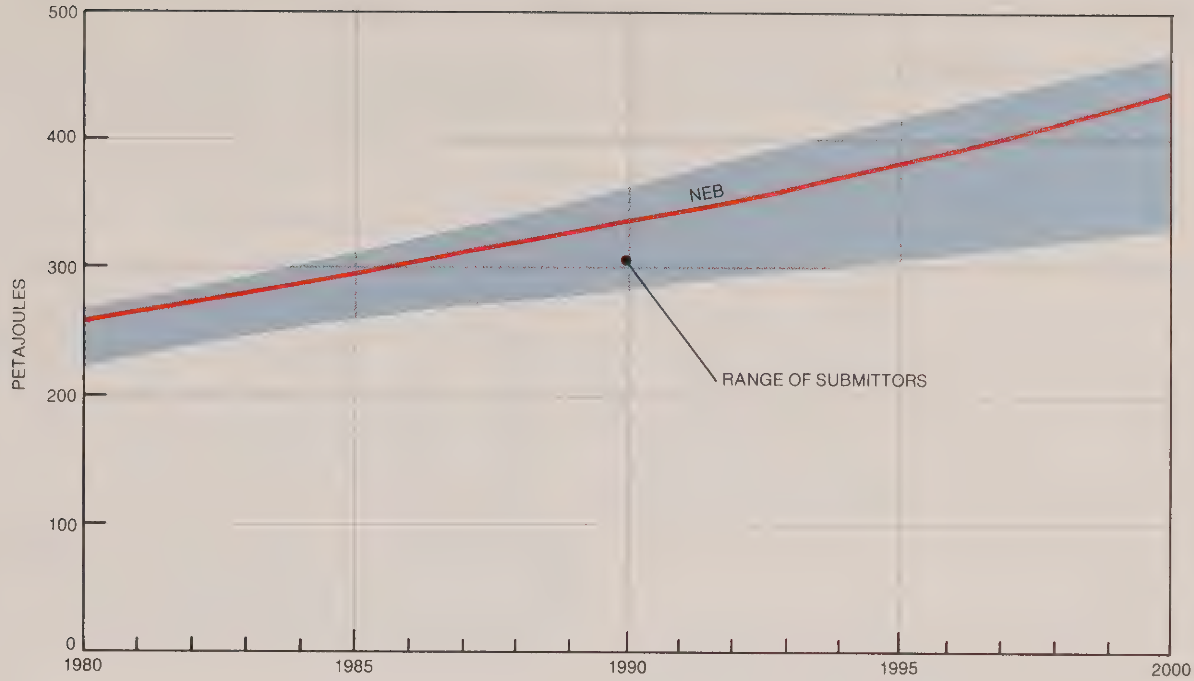

Figure 6-10 Energy Demand for Other Non-Energy Uses
Comparison of Forecasts

Imperial and Petro-Canada stated that their forecasts assumed strong asphalt demand in Western Canada as a result of rapid economic growth. Imperial assumed slower growth of asphalt demand in Eastern Canada because of lower economic growth and increased use of concrete, whereas Gulf envisaged more efficient use of asphalt.

Both Gulf and Imperial indicated that technological improvements in the quality of lubricating oils and greases were incorporated in their forecasts.

Views of the Board

The Board's forecast of demand for petroleum products for non-energy uses other than petrochemical feedstocks is presented in Table 6-38, which also provides the highest and lowest estimates of the Submittors.

The Board forecasts total other non-energy uses to increase at an average annual rate of 2.7 percent, from 259 petajoules in 1980 to 438 petajoules in 2000. Asphalt demand is expected to show the highest increase, at 3.1 percent per year. The demand for lubes and greases and the demand for other products are forecast to increase at average annual rates of 2.8 percent and 1.5 percent respectively. Asphalt is forecast to be about 62 percent of total other non-energy uses by the year 2000, a relatively slight increase from current levels. Lubes and greases are forecast to account for about 18 percent of the total, little change from 1980. The proportion of other products is forecast to decline from 25 percent at present to about 20 percent by the end of the forecast period.

Other non-energy uses are expected to increase at a greater rate in Western Canada than in Eastern Canada, particularly in Alberta and British Columbia, reflecting a higher forecast of economic growth in Western Canada.

Table 6-38

TOTAL DEMAND FOR OTHER NON-ENERGY USES BY ENERGY FORM - CANADA
(Excluding Petrochemical Feedstocks)
Comparison of Forecasts
(Petajoules)

	1980			1990			2000		
	NEB	Submittors		NEB	Submittors		NEB	Submittors	
		High	Low		High	Low		High	Low
Asphalt	149	153	129	201	209	149	273	290	172
Lubes and Greases	45	45	41	58	64	55	77	84	71
Other Products	65	78	42	77	99	47	88	123	52
Total(1)	259	265	224	336	362	285	438	466	333

(1) Not necessarily the sum of the above petroleum products as the high and low demand for particular petroleum products often represent different Submittors.

6.8 Own Use and Losses

Views of Submittors

The category of own use and losses relates to energy consumption by the energy supply industry. It includes fuels used by pipelines and refineries, and transmission and distribution losses. Gulf, Imperial, Shell and Texaco provided forecasts of total energy demand in this sector. Table 6-39 and Figure 6-11 compare their projections with that of the Board.

There were considerable differences in the Submittors' estimates for 1980, partly because of differences in definition, for example some forecasts apparently included natural gas reprocessing shrinkage. Submittors expected that own use and losses of oil would decrease as the use of oil decreases, but own use and losses associated with electricity were expected to increase steadily with increasing electricity demand. Estimates of natural gas fuel and losses were shown to increase initially, decrease, then increase again.

Table 6-39

TOTAL ENERGY DEMAND BY THE ENERGY SUPPLY INDUSTRY - CANADA
OWN USE AND LOSSES
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000	AAI-% 1980-2000
Gulf(1)	706	931	1 046	1 117	1 135	2.4
Imperial	479	509	470	489	533	0.5
Shell(1)	529	573	511	525	557	0.3
Texaco(2)	679	720	779	850	948	1.7
NEB	493	563	545	583	648	1.4

(1) Supplemental Forecast
(2) Pre-NEP forecast shown, since supplemental forecast did not provide complete details for all energy forms in this sector.
AAI—Average Annual Increase

Imperial stated that, as a result of projected improvements in efficiency, energy supply industry use was expected to show only modest growth. Imperial also stated that its projections did not include energy requirements associated with possible frontier gas and oil developments.

Texaco stated that higher energy losses associated with synthetic fuel production would be more than off-set by increased efficiencies in all segments of energy production. As a result, it expected that this sector would grow at less than the overall average for primary energy demand, that is 1.7 versus 2.3 percent per year.

Views of the Board

The Board forecasts that own use and losses by the energy supply industry will increase at an average annual rate of 1.4 percent from 493 petajoules in 1980 to 648 petajoules in 2000. The Board's projections for individual energy forms are shown in Table 6-40. Submittors provided insufficient detail on individual fuels to permit a comparison with the Board's forecast.

The energy supply industry is forecast to decrease its consumption of oil through the year 1990, after which the own use of oil is projected to increase slightly. This reflects projected total market demand for oil in Canada. Over the whole forecast period, the energy supply industry's use of oil is forecast to decline at an average annual rate of 0.3 percent.

The Board estimates pipeline fuel and losses associated with the transportation and distribution of natural gas in domestic markets and in the export of natural gas. While export volumes are decreasing, domestic requirements are forecast to increase. The net result is that own use and losses of natural gas are forecast to increase steadily to 1985, to decline somewhat until the early 1990s, and then to increase again thereafter. For the forecast period overall, gas requirements by the industry are projected to grow at an average annual rate of 2.5 percent.

Own use of electricity, LPG's and coal is expected to increase steadily throughout the forecast period, reflecting the projected increase in demand for these energy forms.

Table 6-40

ENERGY DEMAND BY THE ENERGY SUPPLY INDUSTRY BY ENERGY FORM - CANADA OWN USE AND LOSSES
NEB Forecast
(Petajoules)

	1980	1985	1990	1995	2000	AAI-% 1980-2000
Natural Gas	101	155	126	138	164	2.5
Oil (excluding LPG)	263	250	239	241	247	–0.3
LPG[1]	5	6	8	9	9	3.2
Electricity	119	146	165	186	216	3.0
Coal	5	6	7	9	12	5.1
Total Own Use and Losses	493	563	545	583	648	1.4

[1] Excludes refinery feedstocks and solvent flooding.

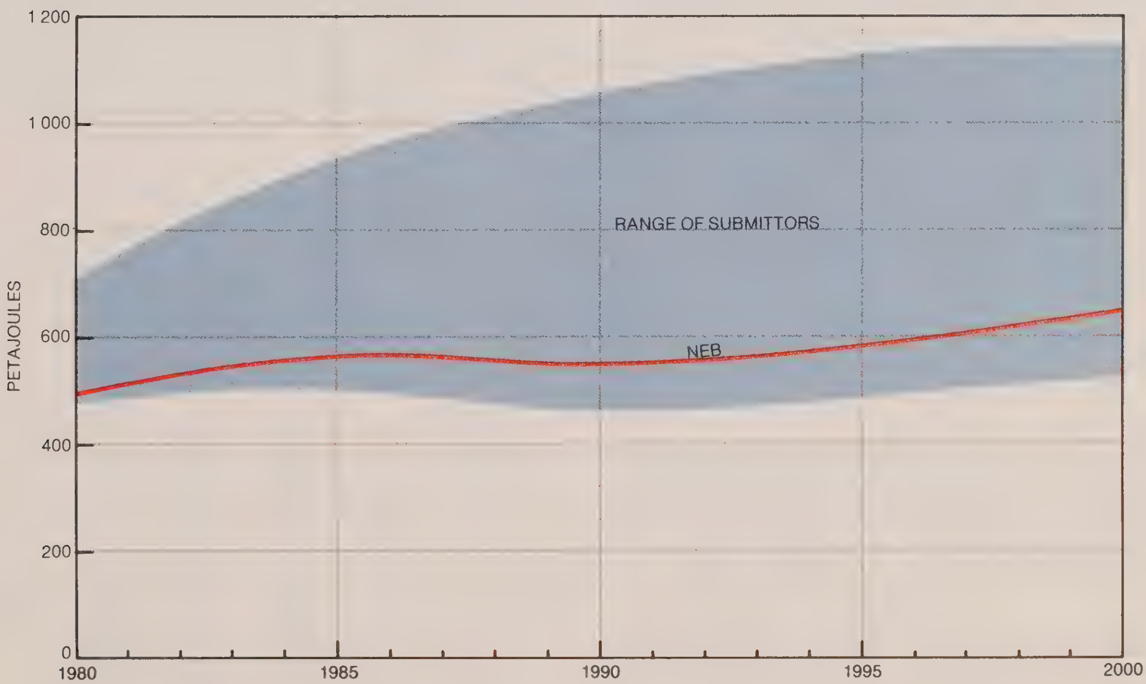

Figure 6-11 Energy Demand in the Energy Supply Industry
Comparison of Forecasts

CHAPTER 7
DEMAND FOR ENERGY BY ENERGY FORM — MIDDLE CASE

7.1 Introduction

In this chapter, the total demand by all sectors for each energy form is discussed and the Board's middle case forecast is compared with the forecasts of the Submittors. To a large extent, the material presented here is of a summary nature only since the demand for individual fuels within particular market sectors was discussed in detail in the preceding chapter. Some Submittors, however, only provided forecasts of the demand for individual energy forms in total and did not disaggregate the totals by market sector. Hence, the forecasts of these Submittors were not included in the forecast comparisons by market sector.

Each section of this chapter includes a tabulation of the Submittors' forecasts, at five-year intervals, for the period 1980 to 2000. In addition, the average annual growth rates implied by these forecasts are presented for the intervals 1980 to 1990, 1990 to 2000, and 1980 to 2000. Much of the discussion relates to the demand for each fuel at a national level. Comparisons of the demand projections for individual provinces are presented in Appendix H.

7.2 Demand for Natural Gas

Views of Submittors

The Submittors' forecasts of Canadian primary natural gas demand are compared in Table 7-1. By the year 2000, these forecasts range from a low of 2 671 petajoules, by Dome, to a high of 3 668 petajoules, by Texaco. Texaco's forecast assumed NEP energy prices and policies while Dome's forecast did not.

Table 7-1

PRIMARY NATURAL GAS DEMAND - CANADA
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000
CPA	1945[2]	—	2578	—	—
Dome	1756	2332	2482	2540	2671
Gulf[1]	1888	2443	2852	3225	3496
Imperial	1751	2094	2405	2649	2814
Norcen[1]	1685	2117	2310	2524	2723
NOVA	1833	2156	2404	2766	3145
Petro-Canada[1]	1789	2334	2647	3002	3338
Shell[1]	1864	2355	2899	—	3447
Texaco[1]	2006	2385	2815	3226	3668
TCPL[1]	1800	2471	2689	2814	2961
NEB	1781	2323	2664	2955	3410

(1) Supplemental Forecast
(2) 1979

Most Submittors expected the primary energy demand market share of natural gas to increase up to the year 1990. After 1990, most Submittors forecast a constant or slightly declining market share for natural gas. Shell, however, predicted that natural gas would increase its market share throughout the forecast period due to the assumption that natural gas would maintain its competitive price advantage over electricity.

The increased market share of natural gas up to 1990 was reflected in the Submittors' estimated average annual growth rates. As shown in Table 7-2, the Submittors, with the exception of NOVA, projected greater growth in the 1980 to 1990 period than in the 1990 to 2000 period. According to the Submittors, the most important factors underlying this greater growth in the 1980s were expansion of natural gas markets and increased petrochemical and industrial demand in Western Canada.

Table 7-2

PRIMARY NATURAL GAS DEMAND - CANADA
GROWTH RATES
Comparison of Forecasts
(Percent per Annum)

	1980 - 1990	1990 - 2000	1980 - 2000
CPA	2.6[2]	—	—
Dome	3.5	0.7	2.1
Gulf[1]	4.2	2.1	3.1
Imperial	3.2	1.6	2.4
Norcen[1]	3.2	1.7	2.4
NOVA	2.7	2.7	2.7
Petro-Canada[1]	4.0	2.3	3.2
Shell[1]	4.5	1.7	3.1
Texaco[1]	3.4	2.7	3.1
TCPL[1]	4.1	1.0	2.5
NEB	4.1	2.5	3.3

(1) Supplemental Forecast
(2) 1979 - 1990

Most Submittors incorporated the expansion of natural gas markets in their forecasts of energy requirements. The major areas of gas expansion were associated with the extension of natural gas pipelines to Québec City, New Brunswick and Nova Scotia and to Vancouver Island. Minor areas of gas expansion were forecast for Ontario and Manitoba.

The Submittors' forecasts of natural gas demand in Québec in the combined residential, commercial and industrial sectors are compared in Table 7-3. Estimated average annual growth rates, over the period 1980 to 2000, ranged from a low of 4.4 percent by Gulf to a high of 7.7 percent by Shell, although the majority of estimates were between 6.4 percent and 6.9 percent.

Table 7-3

NATURAL GAS DEMAND - QUEBEC
RESIDENTIAL, COMMERCIAL AND INDUSTRIAL SECTORS
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000	AAI-% 1980-2000
Dome	105	197	281	351	423	7.2
Gaz Metro	98	255	282	317	357	6.7
Gulf(1)	101	160	188	211	237	4.4
Imperial	102	198	292	327	356	6.4
Petro-Canada(1)	97	202	288	334	359	6.8
Shell(1)	107	203	288	—	473	7.7
TCPL(1)	105	296	340	376	401	6.9
TQM(1)	106	292	319	351	384	6.6
NEB	102	194	277	312	352	6.4

(1) Supplemental Forecast
AAI - Average Annual Increase

Table 7-4 compares the Submittors' forecasts of natural gas demand in the Maritimes. Petro-Canada provided the highest forecast of natural gas demand in the Maritimes. This forecast, which assumed the pricing and policy programs outlined in the NEP, was very similar to TQM's forecast up to 1990. However, by the year 2000, Petro-Canada's forecast was 31 petajoules higher. Dome, Norcen and Texaco had the lowest overall forecasts of natural gas demand. Both Dome and Norcen adopted the Board's forecast of natural gas demand in the Maritimes from its April 1980 Reasons for Decision.

Minor increases in natural gas demand were expected as a result of the extension of natural gas service to Vancouver Island. Most Submittors indicated sales starting in 1983. The British Columbia government projected natural gas demand on Vancouver Island of 20 petajoules in 1996, the last year of its forecast. Similarly, Shell and Texaco indicated volumes of 23 petajoules and 19 petajoules respectively in the year 2000. Westcoast provided the highest forecast of natural gas demand on Vancouver Island. However, a significant proportion of this demand, 66 percent in 1989 and 46 percent in 1999, was attributed to large volume industrial customers. By the year 2000, Westcoast projected natural gas demand of 49 petajoules.

Most Submittors providing supplemental forecasts after the announcement of the NEP indicated higher natural gas demand in 1990. Generally, this higher demand was attributed to lower natural gas prices relative to fuel oil and the inclusion of natural gas extension demand previously not forecast. Other elements of the NEP such as the conversion assistance grants, the market development bonuses and the expected upgrading of refineries in Ontario and Québec were usually not taken into account or were only considered in qualitative terms.

Many of the natural gas distribution companies commented on these elements of the NEP. Those distributors which had conversion rental programs — Consumers', Inland and Union — anticipated that the conversion assistance grants would only replace these programs. Both Consumers' and Union, which have mature natural gas distribution systems, expected that the market development bonuses would have little impact in their service areas.

Table 7-4

NATURAL GAS DEMAND - THE MARITIMES(2)
Comparison of Forecasts
(Petajoules)

	1982	1983	1984	1985	1990	1995	2000
Dome	6	10	23	39	43	54	63
Gulf(1)	0	7	14	20	48	65	69
Imperial	0	0	0	0	59	84	101
Inter City Gas	0	8	47	55	67	—	—
Norcen(3)	0	5	28	37	49	56	63
NOVA	6	26	31	35	48	71	91
Petro-Canada(1)	1	9	19	31	74	107	134
Shell(1)	0	0	0	23	46	64	79
Texaco(3)	0	0	0	0	48	60	60
TCPL(1)	1	7	17	31	73	89	103
TQM(1)	1	7	17	30	73	89	103
NEB	0	3	12	26	64	79	96

(1) Supplemental Forecast
(2) Excluding demand for electrical generation
(3) Fuel displacement volumes

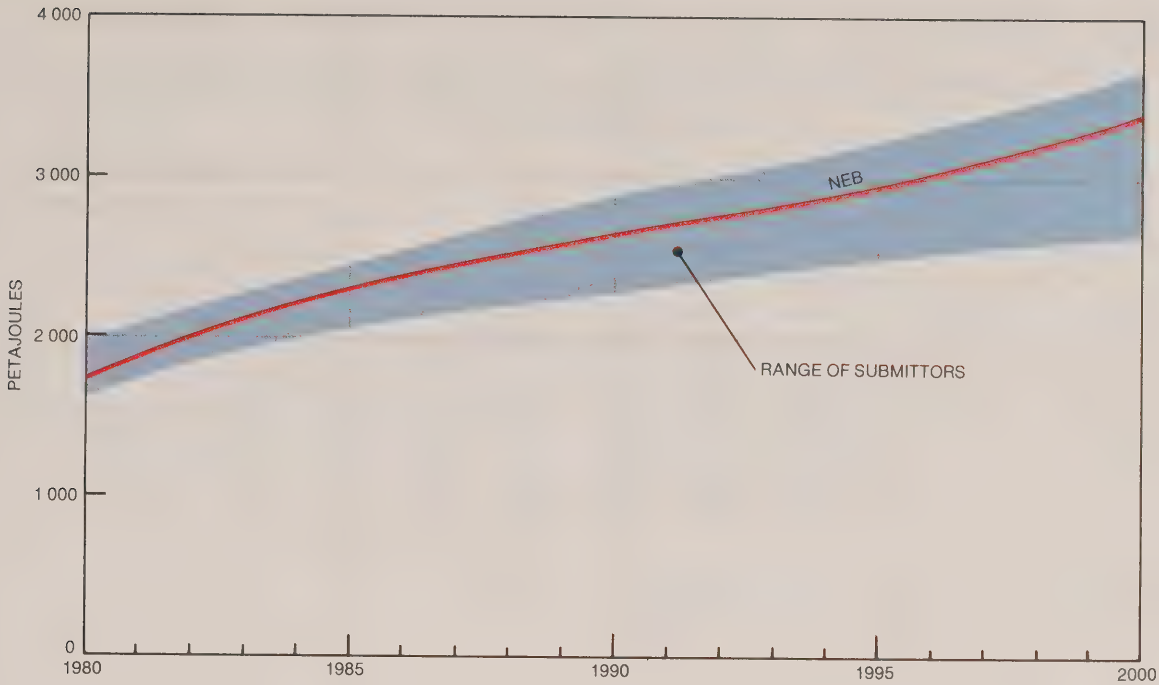

Figure 7-1 Demand for Primary Natural Gas
Comparison of Forecasts

Views of the Board

The Board forecasts primary natural gas demand in Canada to increase from a level of 1 781 petajoules in 1980 to 3 410 petajoules in the year 2000 as shown in Table 7-1 and Figure 7-1. This represents an average annual growth rate of 3.3 percent over the forecast period. Growth is forecast to be greater in the 1980 — 1990 period than in the 1990 — 2000 period as shown in Table 7-2.

The primary energy demand market share of natural gas is expected to increase to 20.7 percent by 1990 and then remain approximately constant over the remainder of the forecast period. This increased market share up to 1990 reflects increased petrochemical and industrial demand in Western Canada and the extensions of the natural gas pipelines.

The Board's forecast includes natural gas extension to Québec City in 1982, the Maritimes in 1983 and Vancouver Island in 1983. Minor natural gas expansion volumes are forecast in Ontario and Manitoba between 1981 and 1985.

For the natural gas market east of Montreal, the Board reassessed its forecast included in the April 1980 Reasons for Decision. In light of the evidence presented and the expected impact of the NEP, the Board revised upward its forecast of natural gas extension demand. Further details on the Board's forecast of natural gas demand are shown separately for New Brunswick and Nova Scotia in Appendix H. It should be noted that the Board is to publish a forecast in respect of TQM's application to construct a natural gas pipeline to New Brunswick and Nova Scotia.

With regard to the possible extension of natural gas service to Vancouver Island, the Board has adopted the estimates of the British Columbia government which forecasts service beginning in 1983. These estimates have been extended to the year 2000 since British Columbia's forecast ended in 1996.

7.3 Demand for Refined Petroleum Products

Views of Submittors

The total demand for refined petroleum products, excluding LPG's, forecast by the Submittors, is presented in Table 7-5. All Submittors, except Dome and Gulf, forecast that total petroleum product demand in Canada would decline slightly by the end of the forecast period from the 1980 level. Dome and Gulf forecast modest increases.

Table 7-5

TOTAL DEMAND FOR REFINED PETROLEUM PRODUCTS - CANADA(1)
Comparison of Forecasts

	Petajoules					Average Annual Increase - %		
	1980	1985	1990	1995	2000	1980-1990	1990-2000	1980-2000
CPA	4 105	—	4 334	—	—	0.5	—	—
Dome(3)	3 823	3 686	3 690	3 894	4 190	–0.4	1.3	0.5
Gulf(2)	4 085	3 854	3 820	3 923	4 127	–0.7	0.8	0.1
Imperial	4 073	3 956	3 789	3 871	3 960	–0.7	0.4	–0.1
Norcen(2)	4 092	3 750	3 652	3 654	3 810	–1.1	0.4	–0.3
NOVA	4 146	3 967	3 991	3 942	4 129	–0.4	0.3	0.0
Petro-Canada(4)	3 682	3 485	3 407	3 453	3 624	–0.8	0.6	–0.1
Shell(2)	4 133	4 013	3 749	—	3 956	–1.0	0.5	–0.2
Texaco(2)	4 096	3 894	3 808	3 708	3 858	–0.7	0.1	–0.3
NEB	4 008	3 830	3 691	3 835	4 178	–0.8	1.2	0.2

(1) Excludes LPG's; includes oil requirements for electricity generation and energy supply industry own use and losses.
(2) Supplemental Forecast
(3) Excludes electricity generation requirements and energy supply industry own use and losses.
(4) Supplemental Forecast; excludes energy supply industry own use and losses.

Most Submittors forecast that total petroleum product demand would decrease steadily to about the year 1990, after which time, it was expected to increase. NOVA and Texaco projected a further decline to about 1995. While there was some variation in the estimates for 1980, partly attributed to the fact that some Submittors had not included all categories of demand, e.g. industry own use and losses, it was noted that most Submittors had similar estimates of the degree by which the demand for oil was expected to change over the forecast period. For the 1980s, all Submittors, except CPA, projected a decline in market demand that ranged between -0.4 and -1.1 percent per year. CPA's forecast, which had been submitted prior to the announcement of the NEP, showed an annual increase of 0.5 percent to the year 1990, the last year of its forecast, but had allowed for a decline in the contribution of oil to primary energy demand. For the 1990 decade, the Submittors projected growth rates that ranged between 0.1 percent and 1.3 percent per year. Over the entire forecast period, the highest projected growth rate was 0.5 percent per year and the lowest growth rate was -0.3 percent.

The decline projected for the 1980s was essentially the result of significantly reduced demand forecast for light fuel oil and heavy fuel oil, reflecting the off-oil measures of the NEP and the anticipated competition from other energy forms, particularly natural gas and electricity.

Although strong growth in demand was generally forecast for aviation fuels, diesel fuel oil and petrochemical feedstocks, the projected decline in light and heavy fuel oil consumption during the 1980s was more than sufficient to offset it. By about 1990, however, the Submittors forecast that the decline in fuel oils demand would moderate somewhat, while the demand for transportation fuels, aviation and diesel, would continue to be strong. Some Submittors also projected continued strong growth in the petrochemical sector. The resultant outlook was for a slight upswing in product demand during the 1990s.

Since all Submittors expected relatively strong growth for energy demand in total, the share of refined petroleum products, including energy supply industry use, as a percentage of total primary energy demand, was projected to decline from

Table 7-6

SHARE OF REFINED PETROLEUM PRODUCTS AS A PERCENTAGE OF TOTAL PRIMARY ENERGY - CANADA(1)
Comparison of Forecasts (Percentage)

	1980	1985	1990	1995	2000
CPA	40.2	—	33.8	—	—
Dome(2)	—	—	—	—	—
Gulf	40.9	33.7	29.1	26.3	24.7
Imperial	39.8	34.7	30.2	28.3	26.4
Norcen	43.8	36.7	32.9	30.0	28.2
NOVA	42.7	37.0	33.6	30.0	27.9
Petro-Canada(3)	38.9	32.8	28.6	25.5	23.6
Shell	41.5	36.6	31.8	—	29.4
Texaco	40.5	35.4	31.3	27.6	25.6
NEB	38.7	32.5	28.7	27.2	25.8

(1) Calculated on the basis of total petroleum product demand, including all market sectors, non-energy uses, electricity generation requirements and energy supply industry own use and losses.
(2) No forecast of Total Primary Energy provided.
(3) Excluding energy supply industry own use and losses.

current levels, estimated between 39.8 and 43.8 percent, to less than 30 percent by the year 2000, as shown in Table 7-6. By the end of the forecast period, refined petroleum products were projected to have a share that ranged between 24.7 and 29.4 percent of total primary energy.

Views of the Board

The Board's forecast of refined petroleum product demand, excluding LPG's, is compared with the high and low forecasts of the Submittors in Table 7-7 and in Figure 7-2. The Board forecasts that total petroleum product demand will decline at an average annual rate of 0.8 percent between 1980 and 1990, and that it will subsequently increase at an average annual rate of 1.2 percent between 1990 and 2000. This pattern is consistent with the views of most of the Submittors.

Significant decreases in light fuel oil and heavy fuel oil demand during the 1980s are forecast to be only partly offset by the anticipated strong growth in aviation and diesel fuel demand and petrochemical feedstocks. By 1990, however, most of the displacement of light and heavy fuel oil is expected to be completed, and consequently, the decline in fuel oils demand is expected to moderate. At the same time, the demand for aviation and diesel fuel is forecast to show continued strong growth, along with increased demand for petrochemical feedstocks. During the 1990s, therefore, the increased demand which is forecast for these products is expected to more than offset the decrease in the demand for fuel oils.

Fuel oils are expected to lose market share to both natural gas, particularly as a result of gas market expansion in Eastern Canada and Vancouver Island, and to electricity in the residential, commercial and industrial sectors. An underlying assump-

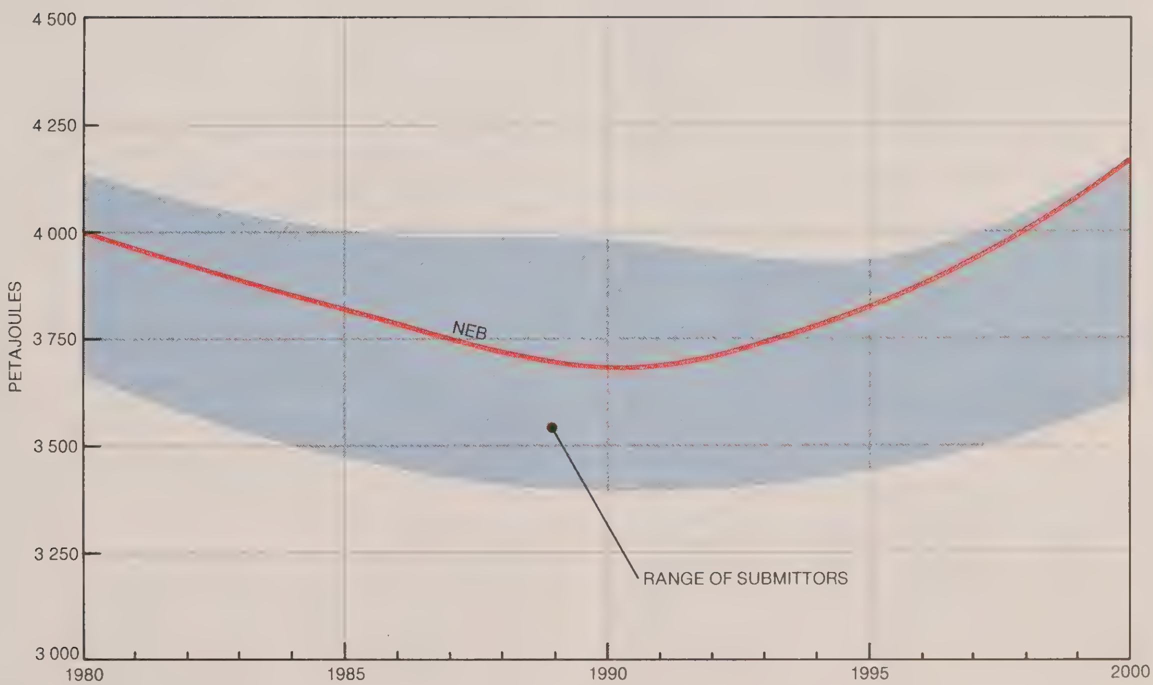

Figure 7-2 Total Demand for Refined Petroleum Products
Comparison of Forecasts

Table 7-7

TOTAL DEMAND FOR REFINED PETROLEUM PRODUCTS BY ENERGY FORM - CANADA[1]
Comparison of Forecasts
(Petajoules)

	1980			1990			2000		
	NEB	Submittors		NEB	Submittors		NEB	Submittors	
		High	Low		High	Low		High	Low
Aviation Fuels	175	184	158	235	269	149	332	359	176
Motor Gasoline	1 341	1 379	1 320	1 212	1 330	1 054	1 115	1 375	814
LFO & Kerosene	607	645	583	315	506	287	216	332	160
Diesel Fuel Oil	581	597	470	873	954	584	1 214	1 374	818
Heavy Fuel Oil	626	707	541	261	514	246	227	503	200
Other Products[1]	678	713	427	795	897	535	1 074	967	593
Total Oil[2]	4 008	4 146	3 682	3 691	4 334[3]	3 407	4 178	4 190	3 624

(1) Excludes LPG; includes petrochemical feedstocks; and includes energy supply industry own use and losses of petroleum products.
(2) The highs (or lows) of Submittors for total oil are not necessarily the sum of the individual fuels shown, since the highs (or lows) for these fuels often represent different Submittors.
(3) CPA submitted the highest estimate for 1990, but this estimate was not included in Figure 7-2 since CPA's forecast did not extend beyond 1990.

tion is that the off oil measures of the NEP will permit market penetration by natural gas, as forecast by the Board, despite the pressure of available supplies of fuel oils. This assumption is accompanied by the equally important corollary that the displaced fuels necessarily manufactured in Eastern Canada will find alternative outlets through secondary processing and/or export. The market shares for light plus heavy fuel oils in the residential, commercial and industrial sectors are forecast as follows:

MARKET SHARES OF LIGHT AND HEAVY FUEL OIL — CANADA

NEB Forecast

(Percent)

	1980	1990	2000
Residential	34.4	15.9	8.7
Commercial	21.8	7.3	3.4
Industrial	18.4	6.1	3.6
Combined Sectors	23.5	8.8	4.6

The Board notes that although the market share of these fuel oils in the three sectors combined is reduced to 8.8 percent in 1990, the off-oil policy target of ten percent is not expected to be reached in the residential sector until later. The forecast indicates that the NEP off-oil policy target for light and heavy fuel oil could be met in aggregate by 1990, although not in every sector for every province.

Tables 7-7 and 7-8 summarize the Board's forecast by major petroleum product category. The implied growth rates are shown in Table 7-9. As previously indicated, the strongest growth in demand throughout the forecast period is expected to be shown by aviation fuels, 3.3 percent average annual growth, diesel fuel oil, 3.8 percent, and petrochemical feedstocks, 4.7 percent. However, only a modest increase in total oil products demand is expected, from 4 008 petajoules in 1980 to 4 178 petajoules in 2000. As a result, the share of refined petroleum products, excluding LPG's, as a percentage of total primary energy demand is forecast to decline from 39 percent in 1980, to 29 percent in 1990, and to 26 percent in the year 2000.

Table 7-8

TOTAL DEMAND FOR REFINED PETROLEUM PRODUCTS BY ENERGY FORM - CANADA[1]
NEB FORECAST
(Petajoules)

	1980	1985	1990	1995	2000
Aviation Fuels	175	206	235	269	332
Motor Gasoline	1 341	1 280	1 212	1 150	1 115
LFO and Kerosene	607	445	315	245	216
Diesel Fuel Oil	581	709	873	1 031	1 214
HFO	626	433	261	254	227
Petrochemical Feedstocks	156	213	221	264	389
Asphalt	149	173	201	232	273
Lubes and Greases	45	51	58	67	77
Other Products	65	71	77	82	88
Industry Own Use and Losses	263	249	238	241	247
Total Oil	4 008	3 830	3 691	3 835	4 178

(1) Excludes LPG, includes industry own use and losses of petroleum products.

Table 7-9

TOTAL DEMAND FOR REFINED PETROLEUM PRODUCTS BY ENERGY FORM - CANADA[1]
GROWTH RATES
NEB FORECAST
(Percent per Annum)

	1980-1990	1990-2000	1980-2000
Aviation Fuels	3.0	3.5	3.3
Motor Gasoline	–1.0	–0.8	–0.9
LFO and Kerosene	–6.3	–3.7	–5.0
Diesel Fuel Oil	4.2	3.3	3.8
HFO	–8.4	–1.4	–4.9
Petrochemical Feedstocks	3.5	5.8	4.7
Asphalt	3.0	3.1	3.1
Lubes and Greases	2.7	2.9	2.8
Other Products	1.6	1.4	1.5
Industry Own Use and Losses	–1.0	0.3	–0.3
Total Oil	–0.8	1.2	0.2

(1) Excludes LPG, includes industry own use and losses of petroleum products.

7.3.1 *Motor Gasoline*

Views of Submittors

With the exception of Shell, Submittors generally estimated demand for motor gasoline as a component of the total energy demand in road transportation. Shell included a small proportion of total demand for motor gasoline, 9 percent in 1980 and 17 percent in 2000, in the industrial sector. The evidence of Submittors generally related not only to estimates of distances travelled by gasoline-powered vehicles and their potential fuel efficiencies but also to possibilities of substitution of motor gasoline by alternate fuels such as diesel, propane and electric power. By the year 2000, Submittors' forecasts ranged from a low of 814 petajoules by Shell to a high of 1 375 petajoules by Dome. Submittors forecasts are compared in Tables 7-10 and 7-11.

With the exception of Dome, Submittors forecast a decline in demand for motor gasoline. In particular, Imperial and Shell expected a more rapid decline in gasoline demand than did other Submittors.

The differences in the average rates of decline in demand for gasoline estimated by Submittors arose mainly from differences in estimates of automobile fuel efficiencies, estimates of expected potential substitution of gasoline by alternative fuels and estimates of fuel conservation by trucks and buses. Thus, the relatively faster rates of decrease in gasoline demand forecast by Imperial and Shell were due mainly to their forecasts of higher fuel efficiencies of cars combined with a higher estimate of substitution of propane for gasoline by Imperial and of diesel, propane and electric power by Shell. Moreover, unlike Gulf, Shell forecast gasoline demand by trucks and buses to decline over the forecast period.

Views of the Board

The Board forecasts the demand for motor gasoline to decrease from 1 341 petajoules in 1980 to 1 115 petajoules in 2000. This represents an average annual decline in demand for gasoline of 0.9 percent, which is a more rapid decline than that forecast by all Submittors except Imperial and Shell. The Board's forecast is compared with Submittors' forecasts in Tables 7-10 and 7-11 and Figure 7-3.

Table 7-10

DEMAND FOR MOTOR GASOLINE - CANADA
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000
Dome	1 353	1 217	1 208	1 277	1 375
Gulf[1]	1 358	1 322	1 267	1 217	1 197
Imperial	1 379	1 320	1 199	1 092	957
Norcen	1 378	1 346	1 328	1 210	1 202
Petro-Canada[1]	1 320	1 218	1 185	1 101	1 116
Shell[1]	1 373	1 192	1 054	—	814
Texaco	1 360	1 286	1 330	1 220	1 222
NEB	1 341	1 280	1 212	1 150	1 115

(1) Supplemental Forecast

Table 7-11

DEMAND FOR MOTOR GASOLINE - CANADA
GROWTH RATES
Comparison of Forecasts
(Percent Per Annum)

	1980 - 1990	1990 - 2000	1980 - 2000
Dome	–1.1	1.3	0.1
Gulf[1]	–0.7	–0.6	–0.6
Imperial	–1.4	–2.2	–1.8
Norcen	–0.4	–1.0	–0.7
Petro-Canada[1]	+1.1	–0.6	–0.8
Shell[1]	–2.6	–2.6	–2.6
Texaco	–0.2	–0.8	–0.5
NEB	–1.0	–0.8	–0.9

(1) Supplemental Forecast

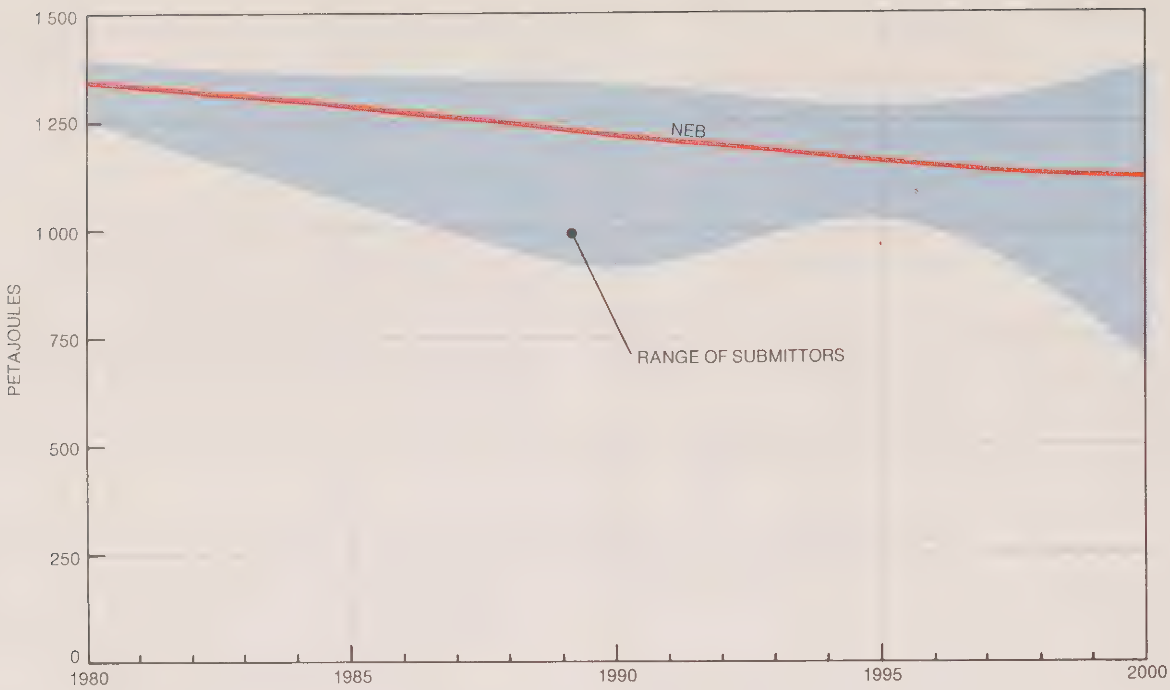

Figure 7-3 Demand for Motor Gasoline
Comparison of Forecasts

The Board's forecast of total demand for gasoline, like those of most Submittors, comprises the sum of gasoline demands by passenger automobiles and in other uses. The Board's projection of a faster decline in total gasoline demand than most Submittors is explained partly by its estimate of a relatively greater decline in distance travelled per automobile, partly by its higher projection of penetration by diesel and propane in the gasoline market and partly by its higher estimate of fuel conservation for trucks and buses.

7.3.2 *Aviation Fuels*

Views of Submittors

Dome, Gulf, Imperial, Norcen, Petro-Canada, Shell, and Texaco provided forecasts of Canadian demand for aviation fuels. The expected average annual rates of growth in these forecasts ranged from 0.4 percent to 3.6 percent for the period 1980 to 2000. These rates reflected slower assumed growth in demand than in the past since high energy prices were expected to induce the use of more efficient aircraft and the adoption of other measures to minimize fuel consumption. Several Submittors felt that improvements in operating efficiencies would have a greater impact in the 1980s than in the 1990s since a lot of existing aircraft would be replaced during the first half of the forecast period. The Submittors' forecasts of the demand for aviation fuels are compared in Table 7-12 and 7-13.

Different trends in demand were expected for each of the two types of aviation fuels. Most Submittors projected a flat demand for aviation gasoline. In contrast, aviation turbo fuel, which is the dominant fuel, was expected by all Submittors to capture practically all of the increased demand for aviation fuels. As a result, the market share for aviation gasoline was expected to decline over the period 1980 to 2000.

Gulf, Imperial, and Shell provided a breakdown of aviation turbo demand by the two types: kerosene and naphtha. These Submittors expected very little change in the shares of each type of fuel over the forecast period. However, the expected share of naphtha turbo fuel was slightly higher for Shell than for Gulf and Imperial. Table 7-14 shows the demand for naphtha type and kerosene type aviation fuels by Submittor.

Views of the Board

The Board forecasts the total demand for aviation fuels — aviation gasoline and aviation turbo fuels — to grow at the average annual rate of 3.3 percent during 1980 to 2000, increasing from 175 petajoules in 1980 to 332 petajoules in 2000. Tables 7-13 and 7-14 and Figure 7-4 compare the Board's forecasts with those of the Submittors.

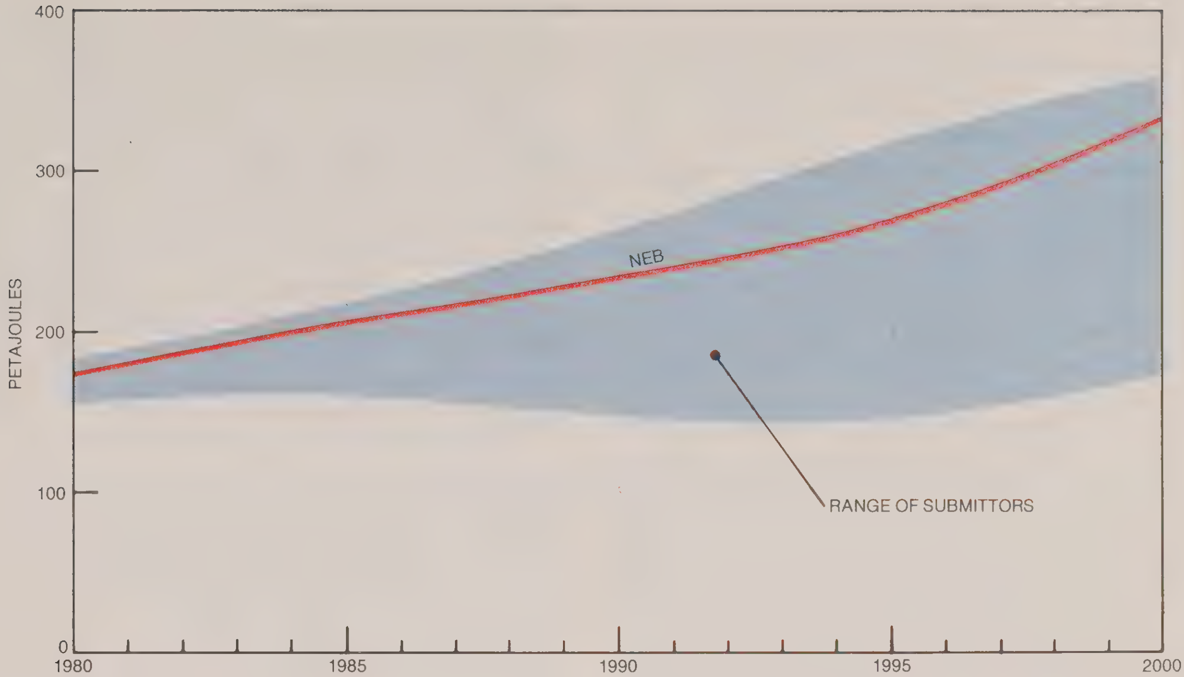

Figure 7-4 Demand for Aviation Fuels
Comparison of Forecasts

Table 7-12

DEMAND FOR AVIATION FUELS - CANADA
Comparison of Forecasts
(Petajoules)

Submittors	1980	1985	1990	1995	2000
Dome	158	173	201	230	253
Gulf(1)	177	206	239	293	355
Imperial	184	218	263	318	357
Norcen	162	163	149	148	176
Petro-Canada(1)	177	197	223	275	359
Shell(1)	172	199	238	285	343
Texaco	161	166	166	173	211
NEB	175	206	235	269	332

(1) Supplemental Forecast

Table 7-13

DEMAND FOR AVIATION FUELS - CANADA
GROWTH RATES
Comparison of Forecasts
(Percent per Annum)

	1980-1990	1990-2000	1980-2000
Dome	2.4	2.3	2.4
Gulf(1)	3.0	4.0	3.5
Imperial	3.6	3.1	3.4
Norcen	–0.8	1.7	0.4
Petro-Canada(1)	2.3	4.9	3.6
Shell(1)	3.3	3.7	3.5
Texaco	0.3	2.4	1.4
NEB	3.0	3.5	3.3

(1) Supplemental Forecast

Table 7-14

SHARE OF DEMAND FOR AVIATION TURBO FUEL BY TYPE - CANADA
(Percent)

Submittors	1980	1985	1990	1995	2000
Gulf[1]					
Naphtha	35.5	34.5	33.9	33.0	32.8
Kerosene	64.5	65.5	66.1	67.0	67.2
Imperial					
Naphtha	31.8	32.5	32.7	31.8	31.3
Kerosene	68.2	67.5	67.3	68.2	68.7
Shell[1]					
Naphtha	37.0	39.9	40.0	40.1	40.2
Kerosene	63.0	60.1	60.0	59.9	59.8

[1] Supplemental Forecast

Higher priced aviation fuels are expected to induce conservation measures by airline companies. As a result, growth in the demand for aviation fuels is expected to be slower than the 5.2 percent growth rate averaged in the seventies. Furthermore, like most Submittors, the Board assumes that most conservation measures will be undertaken in the eighties so that growth in the demand in this decade will be less than that in the nineties.

Consumption of aviation gasoline is expected to remain small while aviation turbo fuels will supply practically all of the increased demand for aviation fuels. Like the Submittors, the Board therefore expects a declining market share for aviation gasoline over the forecast period.

The Board further expects naphtha type turbo fuel to meet 33 percent of turbo fuel requirements by the year 2000, down from the share of 37.6 percent reached in 1980.

7.3.3 *Light Fuel Oil, Kerosene, and Stove Oil*

Views of Submittors

Light fuel oil, kerosene, and stove oil are used as space heating fuels principally in the residential sector, but also in the commercial sector. Small quantities are used for various purposes in the industrial sector, and for electricity generation.

Dome, Gulf, Imperial, Petro-Canada, Shell, and Texaco submitted forecasts for total Canadian demand for light fuel oil, kerosene, and stove oil.

The Submittors expected the demand for these heating oils to decrease throughout the forecast period, citing increasing price competition from natural gas and electricity; furnace conversions; energy conservation measures; and programs of the NEP, such as the furnace conversion grants, the expansion of the CHIP program, the natural gas market development bonuses, and the extension of the natural gas service area to the Maritimes and Vancouver Island.

Gulf, Petro-Canada, and Shell submitted revised forecasts of the demand for heating oil subsequent to the announcement of the NEP. Of these Submittors, Gulf predicted the largest decrease in demand, with total use of heating oil decreasing from 598 petajoules in 1980 to 160 petajoules in the year 2000, an average decline of 6.4 percent per year. Petro-Canada forecast the slowest decrease in demand, from 592 petajoules in 1980 to 305 petajoules in the year 2000, an average annual rate of decline of 3.3 percent.

Texaco submitted its forecast prior to the announcement of the NEP, but indicated that it expected additional reduction in total oil demand in the residential and commercial sectors as a result of the NEP. Most of the oil demand in these sectors represented demand for heating oils.

Submittors' forecasts of demand for light fuel oil, kerosene, and stove oil are shown in Table 7-15.

Table 7-15

DEMAND FOR LIGHT FUEL OIL, KEROSENE, AND STOVE OIL—CANADA
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000
Dome	645	524	506	324	268
Gulf[1]	598	383	287	212	160
Imperial	583	412	297	237	192
Petro-Canada[1]	592	462	361	323	305
Shell[1]	621	485	375	—	246
Texaco	639	513	410	343	332
NEB	607	445	315	245	216

[1] Supplemental Forecast

With the exception of Dome, Submittors expected a more rapid rate of decrease in demand for heating oil during the 1980s than during the 1990s. Dome stated that most of the predicted decrease in demand for heating oils would occur in the 1990s.

Growth rates of demand for heating oils, as forecast by Submittors for total Canada, are compared in Table 7-16.

Table 7-16

DEMAND FOR LIGHT FUEL OIL, KEROSENE, AND STOVE OIL - CANADA
GROWTH RATES
Comparison of Forecasts
(Percent per Annum)

	1980-1990	1990-2000	1980-2000
Dome	–2.4	–6.2	–4.3
Gulf[1]	–7.1	–5.7	–6.4
Imperial	–6.5	–4.3	–5.4
Petro-Canada[1]	–4.8	–1.7	–3.3
Shell[1]	–4.9	–4.1	–4.5
Texaco	–4.3	–2.1	–3.2
NEB	–6.3	–3.7	–5.0

[1] Supplemental Forecast

Views of the Board

The Board forecasts total demand for heating oils in Canada to decrease from 607 petajoules in 1980, to 216 petajoules in the year 2000, an average rate of decline of approximately five percent per year. Between 1980 and the year 2000, the Board expects the demand for heating oils to decline from 411 to 126 petajoules in the residential sector and from 130 to 35 petajoules in the commercial sector. In both sectors the decreased demand for heating oils results from increased price competition from natural gas and electricity, energy conservation, and NEP measures. The Board expects a more moderate reduction in demand for heating oils in the industrial sector, partly because of the greater difficulty of substituting for heating oil in some of its uses in this sector. The Board's forecast is compared with Submittors' forecasts in Tables 7-15 and 7-16 and Figure 7-5.

In 1980, Ontario, Québec, and the Atlantic Region accounted for over 80 percent of Canadian heating oil use. The Board forecasts the demand for heating oils in Eastern Canada to decline, as market shares in Eastern Canada fall to levels that are closer to those being experienced in the Prairie Provinces. However, partly due to their large population, Ontario, Québec, and the Atlantic Provinces are expected to continue to account for over 80 percent of total heating oil use in Canada to the year 2000.

7.3.4 *Diesel Fuel Oil*

Views of Submittors

Diesel fuel oil is consumed primarily in the industrial sector and in road and rail transportation. Smaller quantities are also consumed for marine transportation and in the residential (farm) and commercial sectors. Forecasts of the total demand for diesel fuel oil in Canada over the period 1980 to 2000 were provided by Dome, Gulf, Imperial, Petro-Canada, Shell and Texaco. These forecasts are compared in Tables 7-17 and 7-18. With the exception of Dome and Texaco, all Submittors estimated some growth in diesel fuel oil demand in 1980 over the 1979 demand level of 566 petajoules. Over the forecast period, expected average annual rates of growth in demand for diesel fuel oil ranged from 2.3 percent by Petro-Canada to 4.3 percent by Shell. For many Submittors this contrasted with the weak demand expected for other petroleum products over the same period. As a result, an increasing market share of total energy demand was generally expected for diesel fuel oil by the Submittors. In general, growth was expected to be faster in the 1980s, than in the 1990s, as shown in Table 7-18.

Most Submittors projected the use of diesel fuel oil to increase primarily in the industrial and transportation sectors. The

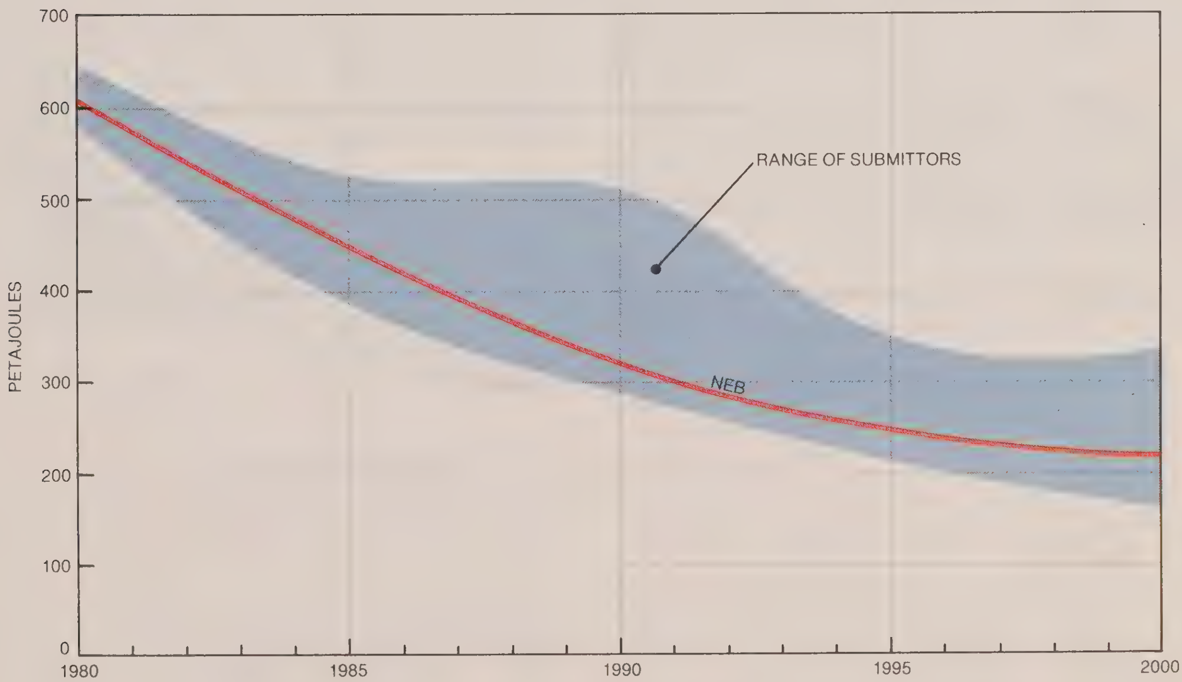

Figure 7-5 Demand for Light Fuel Oil, Kerosene and Stove Oil Comparison of Forecasts

increase in demand for this fuel was attributed to rising activity in both of these sectors and shifts in road transportation fuel demand from gasoline to diesel fuel. This expected shift in demand in road transportation was attributed to the forecast price advantage of diesel fuel oil over other fuels and aggressive marketing of diesel cars by major automobile manufacturers. In the industrial sector, mining development, especially in Western Canada, was expected to contribute greatly to future growth in diesel fuel oil demand.

Table 7-17

DEMAND FOR DIESEL FUEL OIL - CANADA
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000
Dome	533	650	813	986	1 178
Gulf[1]	582	719	884	1 065	1 247
Imperial	594	716	861	1 038	1 196
Petro-Canada[1]	572	672	764	864	899
Shell[1]	597	762	954	1 150	1 374
Texaco	470	519	584	678	818
NEB	581	709	873	1 031	1 214

[1] Supplemental Forecast.

Table 7-18

DEMAND FOR DIESEL FUEL OIL - CANADA
GROWTH RATES
Comparison of Forecasts
(Percent per Annum)

	1980-1990	1990-2000	1980-2000
Dome	4.3	3.8	4.0
Gulf[1]	4.3	3.5	3.9
Imperial	3.8	3.3	3.6
Petro-Canada[1]	2.9	1.6	2.3
Shell[1]	4.8	3.7	4.3
Texaco	2.2	3.4	2.8
NEB	4.2	3.4	3.8

[1] Supplemental Forecast.

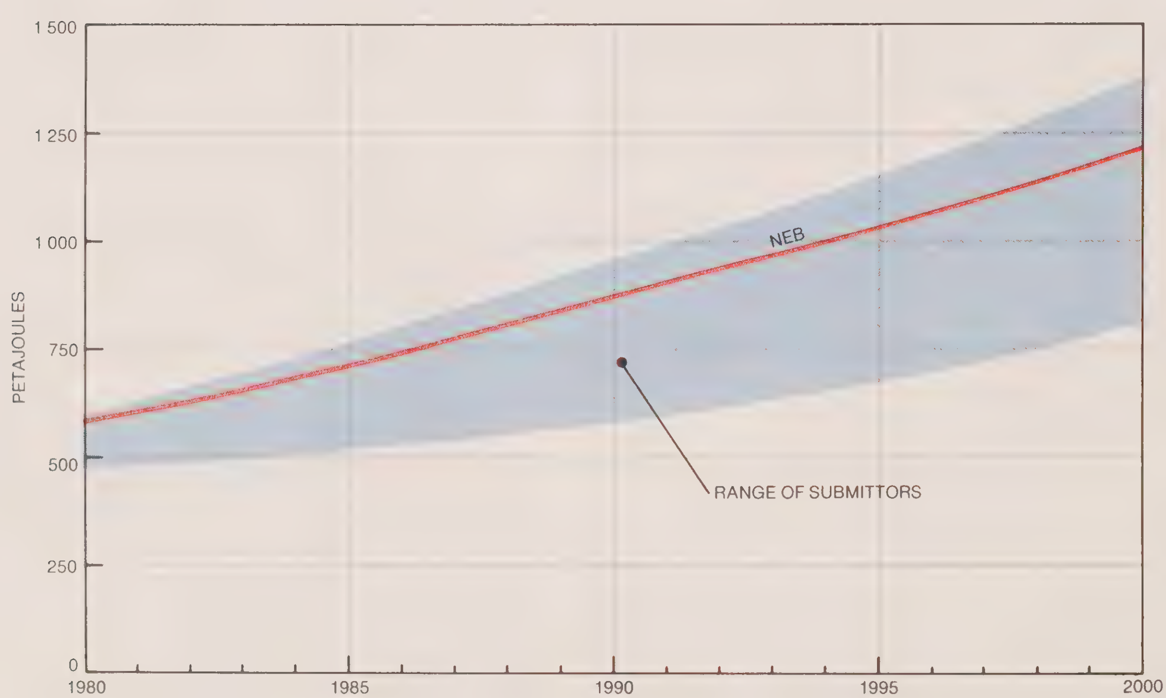

Figure 7-6 Demand for Diesel Fuel Oil
Comparison of Forecasts

Petro-Canada expected a decline in diesel fuel oil demand for thermal electric generation and in the commercial sector as natural gas and electricity become relatively less expensive than diesel fuel oil and as natural gas becomes more available for commercial use. The other Submittors expected little growth in diesel fuel oil demand in these sectors over the forecast period.

With regard to the effect of the NEP, Gulf and Petro-Canada had opposing points of view on the effect of the NEP. Gulf expected the average annual rate of growth in demand for diesel fuel oil to increase from 2.8 percent to 3.9 percent over the forecast period, and Petro-Canada expected this rate to decrease from 4.0 percent to 2.3 percent over the same period. Both Gulf and Petro-Canada expected most of the impact of the NEP on diesel fuel oil demand to be felt in the road transportation sector.

In light of the higher energy prices projected in the NEP, Gulf assumed a higher ratio of diesel to gasoline consumption in the agriculture and commercial trucking fleets. Petro-Canada, on the other hand, reasoned that increasing diesel prices would lower its price advantage over other fuels and therefore lessen the rate of conversion from gasoline vehicles and also encourage the substitution of diesel by natural gas and electricity in industrial applications in non-remote locations.

Views of the Board

The Board estimates total diesel fuel oil demand to grow at an average annual rate of 3.8 percent from 1980 to 2000, with stronger growth forecast in the 1980s than in the 1990s.

It is expected that among sectors, road consumption of diesel will increase at the highest rate and commercial use of diesel at the lowest. The high rate of growth forecast for road diesel consumption reflects the forecast growth in real domestic product, expected substitution of diesel fuel for gasoline in automobiles and trucks, and the expectation that the potential for conserving fuel through increasing fuel efficiencies of diesel trucks will be limited.

Like the Submittors, the Board forecasts an increasing share of total energy demand for diesel fuel oil over the forecast period. The Board's forecasts are compared with those of the Submittors in Tables 7-17 and 7-18 and Figure 7-6.

7.3.5 *Heavy Fuel Oil*

Views of Submittors

Heavy fuel oil is used primarily in the industrial, commercial, and marine sectors as well as for generation of electricity. Relatively small quantities of heavy fuel oil are used in the residential sector.

Forecasts of total demand for heavy fuel oil in Canada submitted by Dome, Gulf, Imperial, Petro-Canada, Shell and Texaco are shown in Table 7-19. The range of the Submittors' forecasts are presented graphically in Figure 7-7.

All Submittors projected a decline in the demand for heavy fuel oil in Canada over the next two decades, resulting from anticipated expansion of natural gas pipelines in Eastern Canada and to Vancouver Island, and measures outlined in the NEP. NC Gas also referred to considerations regarding the greater security of supply of natural gas compared to heavy fuel oil.

Table 7-19

DEMAND FOR HEAVY FUEL OIL - CANADA(2)
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000
Dome	707	622	514	496	503
Gulf(1)	657	368	246	205	200
Imperial	618	—	341	—	247
Petro-Canada(1)	646	459	345	332	354
Shell(1)	660	604	386	—	377
Texaco	541	471	367	321	285
NEB	626	433	261	254	227

(1) Supplemental Forecast
(2) Excludes heavy fuel oil consumption in energy supply industries.

There were wide differences, among the Submittors, in the rates at which the demand for heavy fuel oil was projected to decline. Over the forecast period, expected average annual rates of decline in the demand for heavy fuel oil ranged from 5.8 percent by Gulf to 1.7 percent by Dome as shown in Table 7-20.

Differences in Submittors' estimates of heavy fuel oil consumption for 1980 and their forecasts of demand in subsequent years were largely due to the differences in underlying assumptions regarding their total energy forecasts, relative prices, availability of heavy fuel oil, availability of substitutes, and forecasts of market share.

Gulf, Nova Scotia, and a number of other Submittors, expected demand for heavy fuel oil in the 1980s to decline at a faster rate than in the second half of the forecast period, largely due to expected expansion in upgrading facilities in Central and Eastern Canada and to an expected decline in the competitiveness of oil relative to other energy forms. Some of the Submittors indicated conservation to be an additional factor affecting the rate of decline in heavy fuel oil demand.

Most Submittors indicated that markets created for alternative fuels by the reduction in heavy fuel oil demand would be satisfied mainly by natural gas, and to a lesser extent by coal, wood wastes, and electricity.

Among major consuming sectors, reduction in the demand for heavy fuel oil in the industrial sector was projected by Imperial and other Submittors to be significant. Newfoundland, however, forecast little change in the demand for heavy fuel oil used for steam raising in the province. Norcen stated, that natural gas would be the main fuel penetrating the industrial market currently using heavy fuel oil. While a number of Submittors agreed with Norcen, others assumed that there would be an increasing consumption of coal and wood wastes at the expense of heavy fuel oil.

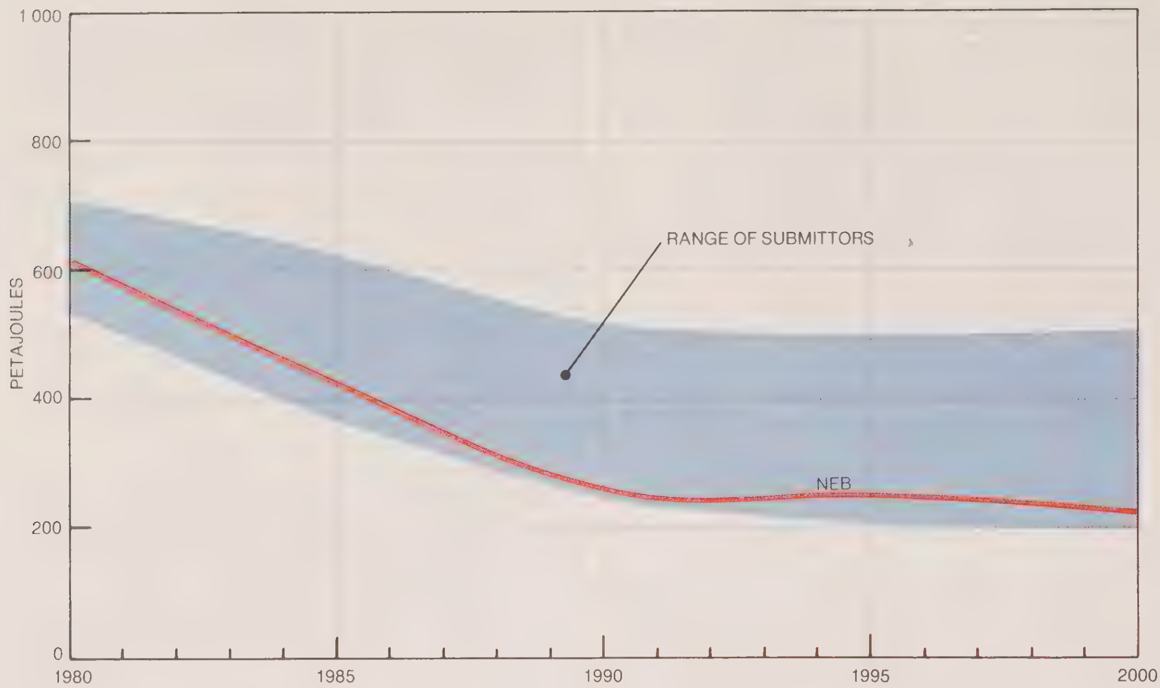

Figure 7-7 Demand for Heavy Fuel Oil
Comparison of Forecasts

Table 7-20

DEMAND FOR HEAVY FUEL OIL - CANADA
GROWTH RATES
Comparison of Forecasts
(Percent per Annum)

	1980 - 1990	1990-2000	1980-2000
Dome	–3.1	–0.2	–1.7
Gulf(1)	–9.4	–2.0	–5.8
Imperial	–5.8	–3.2	–4.5
Petro-Canada(1)	–6.1	0.3	–3.0
Shell(1)	–5.2	–0.2	–2.8
Texaco	–3.8	–2.5	–3.2
NEB	–8.4	–1.4	–4.9

(1) Supplemental Forecast

Future growth in thermal generation was expected to rely less on oil. The off-oil strategy outlined by the Federal Government and the high cost of oil were expected to limit the use of heavy fuel oil for generation of electricity. Most of the oil-fired thermal generation plants in the Atlantic region and to a lesser extent those in other regions were predicted to be converted to coal-fired plants.

Petro-Canada expected heavy fuel oil demand for electrical generation to be entirely phased out by the year 2000, except for limited use by some oil-fired facilities in Newfoundland. Coal, and to a certain extent natural gas, were expected by Petro-Canada to displace heavy fuel oil as the main fuel for thermal electric generation. Nova Scotia expressed the view that in thermal generation both oil and gas would be more expensive than coal.

In marine transportation, demand for heavy fuel oil was forecast to remain stable or to increase somewhat over the forecast horizon. British Columbia identified the price and availability of heavy fuel oil as being the two major factors affecting the demand for this fuel in marine transportation.

In the commercial sector, where heavy fuel oil is used for space heating, Texaco and most of the other Submittors projected a decline in demand throughout the forecast period. Natural gas and electricity were assumed to displace heavy fuel oil.

There appeared to be a general concurrence among the Submittors that the NEP, through its support for upgrading of heavy

fuel oil, coupled with higher relative prices for oil, would significantly reduce the availability and demand for heavy fuel oil, particularly in Central and Eastern Canada.

Views of the Board

The Board forecasts the demand for heavy fuel oil to decline from 626 petajoules in 1980, to 261 petajoules in 1990, and to 227 petajoules by the year 2000 as shown in Table 7-21. The Board's forecast assumes a higher price for oil relative to other major fuels, availability of natural gas in eastern Canada as well as on Vancouver Island, elimination of heavy fuel oil imports, establishment of upgrading facilities, and export of any surplus refinery production of heavy fuel oil.

Table 7-21

DEMAND FOR HEAVY FUEL OIL - CANADA
NEB Forecast(1)
(Petajoules)

Sectors	1980	1985	1990	1995	2000
Residential	17	13	6	3	0
Commercial	67	43	23	15	12
Industrial	373	231	130	106	96
Marine	73	76	81	87	94
Electricity Generation	96	71	22	44	24
Total(2)	626	433	261	254	227

(1) Does not include heavy fuel oil used by the energy supply industry.
(2) Totals may not add up due to rounding-off.

Consumption of heavy fuel oil is forecast to decline in the industrial, commercial, and residential sectors as a result of increased availability of alternative sources of energy at competitive prices. Natural gas, renewable sources of energy such as hog fuel and pulping liquor, and to a certain extent electricity, are expected to displace much of the use of heavy fuel oil in these three sectors.

Consumption of heavy fuel oil for thermal generation of electricity is also projected to decline and to be replaced primarily by coal. The share of coal in total fossil fuels used to generate electricity is projected to increase from about 81 percent in 1980 to 91 percent by the year 2000. At the same time the share of heavy fuel oil is expected to decline from 11 percent in 1980 to about 1 percent by the year 2000.

In marine transportation, where comparatively limited opportunities exist for fuel substitution, demand for heavy fuel oil is expected to increase over the forecast horizon at an average annual rate of 1.3 percent.

On a regional basis, the greatest reduction in the demand for heavy fuel oil is expected to occur in eastern Canada where currently most of the heavy fuel oil is consumed.

Through its support for the upgrading of heavy fuel oil, the expansion of natural gas markets, and other factors such as the use of conversion grants, the National Energy Program is expected to reduce significantly the consumption of heavy fuel oil.

7.3.6 *Other Petroleum Products*

Views of Submittors

The other petroleum products included in the Submittors' demand forecasts were petrochemical feedstocks, asphalt, lubes and greases, and miscellaneous other products. Several Submittors furnished forecasts of total Canadian demand for other petroleum products, and these forecasts are compared with the NEB forecast of demand for other products in Table 7-22. The associated period growth rates are shown in Table 7-23. The range of Submittors' forecasts for the separate products included in this category is shown in Table 7-24.

Table 7-22

DEMAND FOR OTHER PETROLEUM PRODUCTS - CANADA(2)
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000
Dome	427	500	550	580	614
Gulf(1)	437	590	645	681	714
Imperial	441	524	589	659	770
Petro-Canada(3)	414	518	570	605	635
Shell(1)	445	511	535	564	593
Texaco(1)	462	598	703	758	807
NEB	415	508	556	645	827

(1) Supplemental Forecast
(2) Includes petrochemical feedstocks, asphalt, lubes and greases, and miscellaneous other products.
(3) Sum of oil petrochemical feedstocks forecast, which was taken from the Supplemental submission, and other non-energy uses forecast, taken from the September, 1980 submission.

Table 7-23

DEMAND FOR OTHER PETROLEUM PRODUCTS - CANADA(2)
GROWTH RATES
Comparison of Forecasts
(Percent per Annum)

	1980-1990	1990-2000	1980-2000
Dome	2.6	1.1	1.8
Gulf(1)	4.0	1.0	2.5
Imperial	2.9	2.7	2.8
Petro-Canada(3)	3.2	1.1	2.2
Shell(1)	1.9	1.0	1.4
Texaco(1)	4.3	1.4	2.8
NEB	3.0	4.1	3.5

(1) Supplemental Forecast
(2) Includes petrochemical feedstocks, asphalt, lubes and greases, and miscellaneous other products.
(3) Based on the combined forecast of oil petrochemical feedstocks, taken from the Supplemental submission, and other non-energy uses, taken from the September, 1980 submission.

Table 7-24

DEMAND FOR OTHER PETROLEUM PRODUCTS BY PRODUCTS - CANADA
Comparison of Forecasts
(Petajoules)

	1980			1990			2000		
	NEB	Submittors		NEB	Submittors		NEB	Submittors	
		High	Low		High	Low		High	Low
Petrochemical Feedstocks	156	210	162	221	357	250	389	357	231
Asphalt	149	153	129	201	209	149	273	290	172
Lubes and Greases	45	45	41	58	64	55	77	84	71
Miscellaneous Other Products	65	78	42	76	99	47	88	123	52
Total Other Petroleum Products(1)	415	462	414	556	703	535	827	807	593

(1) Not always the sum of above products as the high and low demand for particular products often represent different Submittors.

Submittors classified different products to this category, as shown by differences in the estimated 1980 demand for these products. Demand estimates for 1980 ranged from 414 petajoules submitted by Petro-Canada to 462 petajoules reported by Texaco. Submittors' forecasts of growth rates of demand for these products from 1980 to 2000 ranged from 1.4 percent per year forecast by Shell to 2.8 percent per year estimated by Imperial and Texaco.

Petrochemical

Dome, Gulf, Imperial, Petro-Canada, Petrosar, Shell, TCPL, Texaco and Union Carbide submitted forecasts of the demand for petroleum for use as petrochemical feedstock.

Petrosar, Shell and TCPL assumed that additional liquid feedstock capacity would be constructed in Alberta during the early 1980s, and in Ontario and Québec.

Texaco suggested that to the extent oil is used as a feedstock in petrochemical processes, low-value refinery streams should be used rather than crude oil. Petro-Canada anticipated increased feedstock production, as a result of expected additional hydroprocessing facilities.

Most Submittors expected the use of oil products by the petrochemical industry to increase during the 1980s, and to remain constant, or perhaps to decline, during the 1990s. Gulf anticipated use of oil as a petrochemical feedstock to remain constant after 1985. Imperial, Petrosar, Union Carbide and TCPL predicted that use of oil as a petrochemical feedstock would increase throughout the forecast period.

Asphalt

Gulf, Imperial, Petro-Canada and Texaco forecast total Canadian demand for asphalt to grow by 3.2 to 3.4 percent per year. Dome and Shell forecast annual growth rates of 1.2 and 1.5 percent, respectively.

Imperial and Petro-Canada expected strong demand for asphalt in Western Canada, due to rapid economic growth. Gulf stated that higher asphalt prices would lead to development of new techniques to limit asphalt demand.

Lubes and Greases

Average annual rates of increase for total Canadian demand for lubes and greases, forecast by Submittors, ranged from 2.6 percent predicted by Dome to 3.2 percent by Petro-Canada. Several Submittors related demand for lubes and greases to industrial growth, for example in manufacturing and mining, and to recent improvements in product quality.

Miscellaneous Other Products

The highest forecast growth in demand for miscellaneous other petroleum products, which includes naphtha specialties, petroleum coke and waxes, was 2.4 percent per year, with most Submittors projecting little growth in demand for these products.

Views of the Board

The Board forecasts total Canadian demand for other petroleum products to increase by 3.5 percent per year, from 415 petajoules in 1980 to 827 petajoules in 2000. The Board's forecast is compared with Submittors' forecasts in Tables 7-22 to 7-24 and Figure 7-8.

The Board forecasts that use of oil products as petrochemical feedstock will increase by 4.7 percent per year, from 156 petajoules in 1980 to 389 petajoules in the year 2000, reflecting planned capacity additions in Eastern Canada and the expected development of the petrochemical industry in Alberta.

The demand for asphalt is expected to grow at an average rate of 3.1 percent per year, from 149 petajoules in 1980 to 273 petajoules by the year 2000. The demand for lubes and greases is expected to increase at an annual rate of 2.8 percent, from 45 petajoules in 1980 to 77 petajoules in the year 2000. Demand for miscellaneous other products is expected to increase from 65 to 88 petajoules between 1980 and 2000. The Board forecasts demand for asphalt, lubes and greases, and other products on the basis of expected Canadian economic growth.

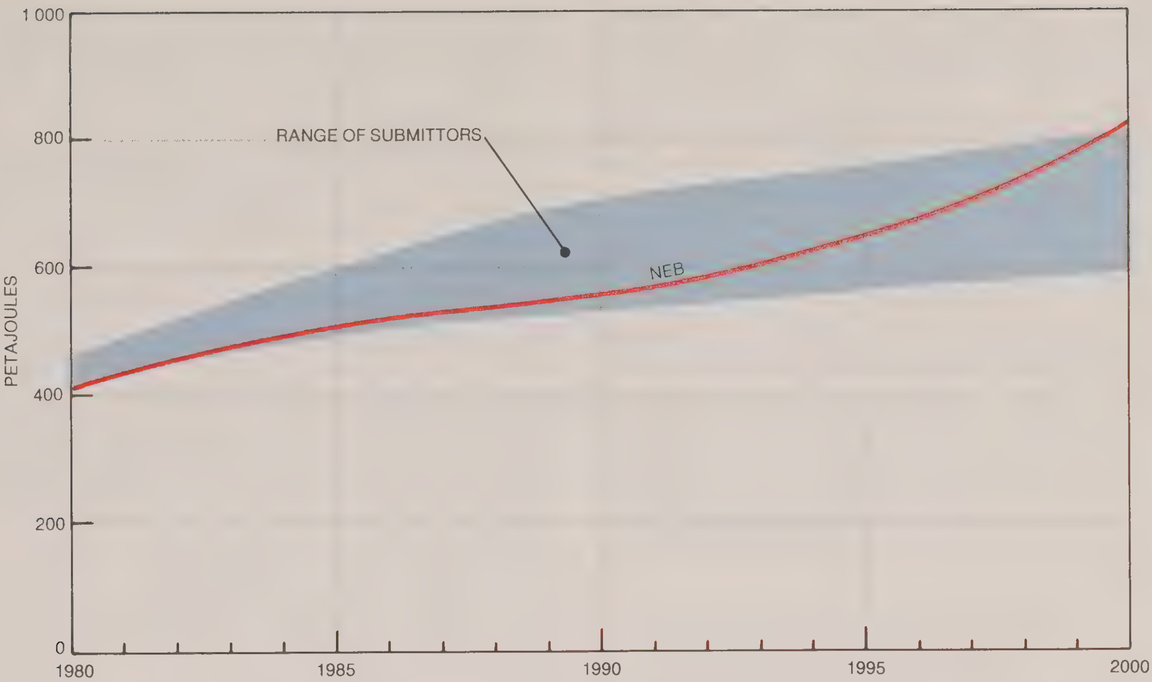

Figure 7-8 Demand for Other Petroleum Products
Comparison of Forecasts

7.4 Demand for Electricity

Views of Submittors

In contrast to discussions of other energy forms, the following discussion deals with electricity, which is a secondary form of energy, rather than the various primary energy forms used for the generation of electricity.

Forecasts of total electricity demand in Canada over the period 1980 to 2000 were provided by Gulf, Imperial, Petro-Canada, Shell and Texaco. Tables 7-25 and 7-26 show the Submittors' forecasts. By the year 2000, these forecasts range from a low of 1 811 petajoules by Shell to a high of 2 604 petajoules by Gulf. Expected average annual growth rates in electricity demand from 1980 to 2000 ranged from 2.0 percent by Shell to 4.1 percent by Petro-Canada.

Most Submittors based their forecasts of electricity demand on the price of electricity in relation to other fuels, and the expected rates of growth in real Gross National Product and total population. Gulf, Imperial, and Texaco projected Canada's real Gross National Product to grow at an average annual rate of 3.0 percent between 1980 and 2000. Shell and Petro-Canada projected economic growth rates of 3.2 percent and 3.5 percent respectively.

All Submittors expected an average annual growth in population of approximately one percent during the 1980s, but for the 1990s expected population growth rates ranged from 0.6 to 0.9 percent per annum.

Table 7-25

DEMAND FOR ELECTRICITY - CANADA(2)
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000
Gulf(1)	1 197	1 475	1 833	2 218	2 604
Imperial	1 193	1 463	1 730	1 986	2 233
Petro-Canada(1)	1 073	1 316	1 600	1 971	2 388
Shell(1)	1 223	1 391	1 545	1 675	1 811
Texaco	1 222	1 507	1 763	2 091	2 470
NEB	1 224	1 450	1 657	1 915	2 285

(1) Supplemental Forecast.
(2) Includes transmission losses.

All Submittors except Texaco and Shell assumed that electricity would become increasingly more price competitive with both natural gas and oil over the forecast period. Gulf, Imperial, and Petro-Canada expected real electricity prices to remain approximately constant during the forecast period while the prices of natural gas and oil were expected to increase in real terms. Texaco foresaw a continuing improvement in electricity's competitive position relative to oil over the entire forecast period, however, relative to gas, only in the first decade. Furthermore, Texaco expected electricity to show a price advantage over oil in the residential sector within the second decade. Shell, with the lowest forecast growth in electricity demand, expected electricity to maintain its present competitive position vis-à-vis natural gas and oil.

All but Petro-Canada expected higher rates of growth in electricity demand during the first decade than in the second decade, as shown in Table 7-26. Slower population growth in the 1990s than in the 1980s was the basic underlying factor. Shell and Imperial also expected a slowdown in economic growth during the 1990s.

In general, the Submittors expected electricity to supply an increasing share of total energy demand in Canada over the forecast period. All Submittors forecast increasing market shares for electricity in the residential and commercial sectors and, excepting Imperial, in the industrial sector as well.

Table 7-26

DEMAND FOR ELECTRICITY - CANADA[2]
GROWTH RATES
Comparison of Forecasts
(Percent per Annum)

	1980 - 1990	1990 - 2000	1980 - 2000
Gulf[1]	4.4	3.6	4.0
Imperial	3.8	2.6	3.2
Petro-Canada[1]	4.1	4.1	4.1
Shell[1]	2.4	1.6	2.0
Texaco	3.7	3.4	3.5
NEB	3.1	3.3	3.2

[1] Supplemental Forecast.
[2] Includes transmission losses.

TCPL submitted an electricity demand forecast for each province from Ontario to British Columbia. Based on slower GNP and population growth than that experienced in the past, and improved price competitiveness, TCPL forecast a 3.1 percent average annual growth rate for total electricity demand for the five provinces over the forecast period.

Six provincial governments — Newfoundland, Nova Scotia, New Brunswick, Ontario, Manitoba, and British Columbia — provided electricity demand forecasts for their respective provinces. Expected average annual growth in electricity demand over the forecast period ranged from 2.7 percent by Ontario to 4.2 percent by British Columbia. Several of the provinces based their forecasts of electricity demand on assumed economic and demographic conditions, and expected provincial energy prices.

Each provincial government expected electricity to improve its present competitive position in relation to other energy forms. In particular, Nova Scotia assumed increasing competitiveness of electricity over oil in its Province, and the Government of Manitoba assumed that electricity would improve its competitive position to 1995 in relation to oil and natural gas, and maintain that position during the rest of the forecast period.

Several electrical utilities provided electricity load forecasts for their respective service areas. NFLD Light forecast electricity growth in its service area of 5.0 percent per annum to 1985. NBEPC, which did not take into account a natural gas pipeline into New Brunswick, forecast that growth in electricity demand in New Brunswick would average 4.3 percent per year to 1990. Based on the assumptions of 1.0 percent annual population growth in Ontario, and electricity prices increasing until 1984 and stabilizing thereafter, Ontario Hydro projected an average annual growth rate of 3.3 percent in electricity demand in Ontario from 1980 to 2000. SPC forecast electricity demand in Saskatchewan to grow at 4.1 percent per annum to the year 2000.

Views of the Board

The Board forecasts that total electricity demand in Canada will grow at an average annual rate of 3.2 percent increasing from 1 224 petajoules in 1980, to 2 285 petajoules in the year 2000. These totals include the total forecast demand in the residential, commercial, and industrial sectors. Key factors underlying each sectoral forecast are economic activity, population, relative energy prices, conservation and the potential for replacing other fuels with electricity. Tables 7-25 and 7-26 and Figure 7-9 compare the Board's forecasts with those of the Submittors.

In both the residential and commercial sectors, electricity is expected to increase its share of the total energy market by approximately twelve percentage points over the forecast period. This penetration reflects the expectation that the competitive position of electricity for space heating will improve. In contrast, a modest increase of two percentage points is expected for electricity's share of total energy demand in the industrial sector, since it is expected that non-price constraints will limit further penetration in this sector.

The Board expects that the demand for electricity in relation to total demand for energy in the combined residential, commercial and industrial sectors will increase during the forecast period from 24.7 percent in 1980, to 31 percent by the year 2000.

7.5 Demand for LPG

Views of Submittors

Liquefied petroleum gases consist of propane and butanes. At present major markets for propane are as a heating fuel and a

petrochemical feedstock. Lesser amounts of propane are used by the energy industry and in road transportation. Butanes are required by petroleum refiners, and by the petrochemical industry.

Submittors' forecasts of total Canadian use of LPG are shown in Table 7-27. Submittors forecast average rates of increase for the forecast period ranging from 0.9 percent per year expected by Shell to 2.8 percent per year anticipated by Imperial.

As shown in Table 7-28, most Submittors have forecast a higher rate of increase in demand for LPG for the 1980s than for the 1990s. Gulf anticipated increased use of propane and butanes in industry during the 1980s, followed by decreased use during the 1990s as investment in the energy industry declines. Texaco forecast that demand for LPG by the petrochemical industry would increase during the 1980s, but remain constant thereafter. Texaco also expected that use of LPG would decrease throughout the forecast period in the residential and industrial sectors.

Several Submittors provided separate forecasts for propane and butanes.

Table 7-27

DEMAND FOR LPG - CANADA
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000
CPA	100	—	188	—	—
Dome	135	151	160	173	190
Gulf(1)	105	184	273	218	153
Imperial	122	139	170	189	211
Petro-Canada(1)	131	190	210	—	215
Shell(1)	68	73	79	79	81
Texaco	119	146	157	157	152
NEB	89	103	160	210	223

(1) Supplemental Forecast

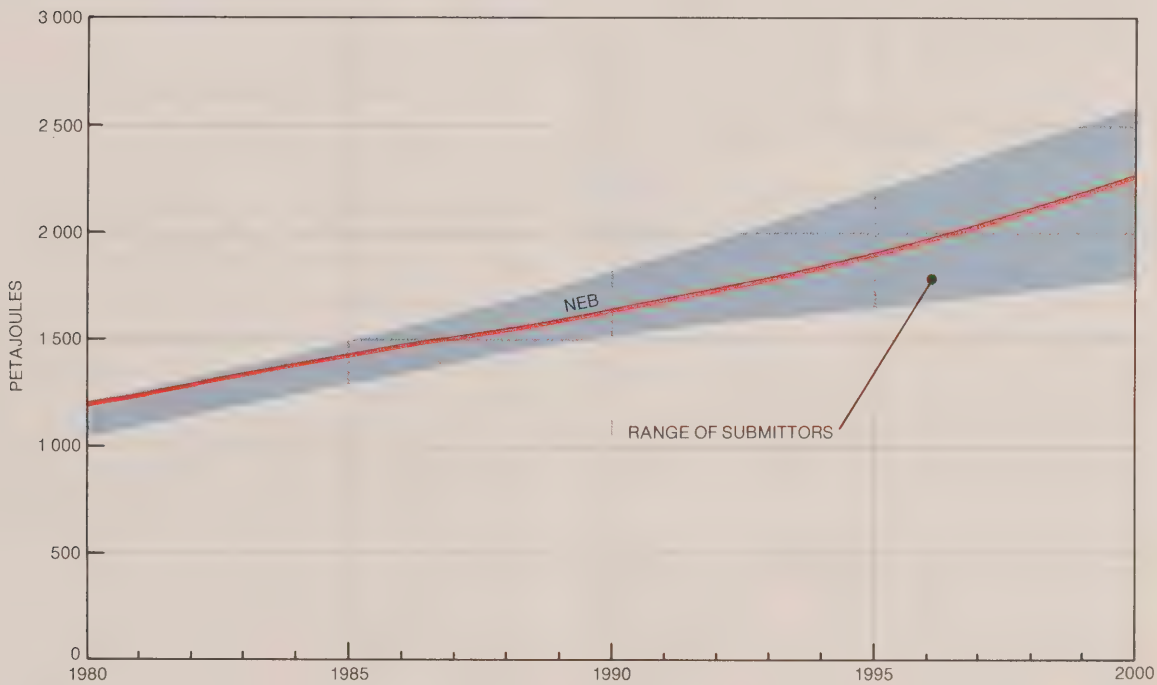

Figure 7-9 Demand for Electricity
Comparison of Forecasts

Table 7-28

DEMAND FOR LPG - CANADA
GROWTH RATES
Comparison of Forecasts
(Percent per Annum)

	1980-1990	1990-2000	1980-2000
CPA	6.5	—	—
Dome	1.7	1.7	1.7
Gulf[1]	10.0	–5.6	1.9
Imperial	3.4	2.2	2.8
Petro-Canada[1]	4.8	0.2	2.5
Shell[1]	1.1	0.6	0.9
Texaco	2.8	–0.3	1.2
NEB	6.0	3.4	4.7

[1] Supplemental Forecast

Propane

Imperial forecast the strongest growth in demand for propane, at 3.3 percent per year. Other Submittors predicted growth rates as low as 1.0 percent per year.

Most Submittors agreed that the greatest increase would occur in the road transportation sector which now derives less than one percent of its requirements from this fuel. Imperial Oil indicated that demand for propane in the transportation sector could grow from almost nil to 37 petajoules by the year 2000, reflecting an anticipated shift from gasoline to propane. Shell stated that it expected propane-fuelled vehicles to account for 7 percent (24 300 vehicles) of new light truck sales in 1990, and 15 percent (64 100 vehicles) in 2000. Most Submittors estimated increased use of propane, but to a lesser degree, in the petrochemical and industrial sectors, and very limited growth in the traditional commercial and residential sectors.

Some Submittors indicated that they were planning marketing initiatives designed to increase the use of propane, principally in Eastern Canada. Petro-Canada advised that it has under active consideration a two-pronged program designed to develop new markets for propane in Atlantic Canada and to convert commercial urban truck and automobile fleets in Ontario to propane. ICG Canadian Propane also indicated that it plans to establish propane as an automotive fuel for commercial fleet operators in Ontario, with 50 million dollars to be invested in auto conversion centres over the next five years. The Company estimated that sales resulting from this new program could reach 600 million litres per year by 1985.

Most Submittors felt that the major obstacle to large scale expansion of propane for the domestic market was the lack of a well developed secondary distribution network, resulting in uncompetitive burner-tip prices; and high costs associated with the conversion of heating systems and vehicles to propane. In this regard, some Submittors cited recent actions by the Government of Ontario to remove the road tax from propane and exempt propane-powered vehicles from the retail sales tax, thus creating a significant incentive for fleet owners to convert to propane. The taxable grants for conversion of furnaces and vehicles from oil, announced in the NEP, were also considered by the Submittors to have provided an impetus to convert to propane. Submittors agreed that a substantial usage of propane in road transportation could be achieved by making it sufficiently price competitive with other fuels.

Petro-Canada reviewed the world-wide supply and demand for total LPG and indicated a possible surplus of 146 000 cubic metres per day by 1986. New supplies expected on the world market would come mainly from the Middle East, the North Sea. Indonesia and Mexico. These new supplies could be brought into the United States thereby creating new competition for Canadian LPG exporters.

Butanes

Several Submittors forecast growth rates of demand for butanes as low as one percent per year or less between 1980 and 2000. Gulf expected that demand for butanes would grow by 2.5 percent per year during the forecast period. The major use of butanes was seen as likely to remain in gasoline blending and as petrochemical feedstock. Some potential for increased usage could exist in the petrochemical sector from new petrochemical plants designed around a butane feedstock.

Views of the Board

The Board expects that the total of residential, commercial and industrial demand for LPG will grow by 0.8 percent per year, from 65 petajoules in 1980 to 76 petajoules by the year 2000. The increased demand for LPG reflects increased total energy demand in these sectors. The Board's forecast of total demand for LPG is compared with Submittors' forecasts in Tables 7-27 and 7-28 and Figure 7-10.

The Board anticipates that use of propane in road transportation will increase by an average rate of 14.1 percent per year, from 2 petajoules in 1980 to 28 petajoules in 2000. As a result of the NEP conversion grants, some vehicle fleets are expected to be converted to propane. However, limited distribution facilities for propane will forestall wider use of propane in road transportation, for example by private automobiles.

The Board anticipates that one world-scale propane-based petrochemical plant will become operational by 1990. Feedstock requirements for this plant, plus the likely growth in the demand for butanes, are expected to amount to 109 petajoules by the year 2000, compared with 17 petajoules in 1980.

Use of LPG by the energy supply industry, excluding refinery feedstocks and solvent flooding, is forecast to increase from five to nine petajoules during the period 1980 to 2000.

7.6 Demand for Ethane

Views of Submittors

Submittors estimated demand for ethane mainly on the basis of their forecasts of ethane-based ethylene capacity, though some expected additional small quantities of ethane to be used in miscible flooding operations.

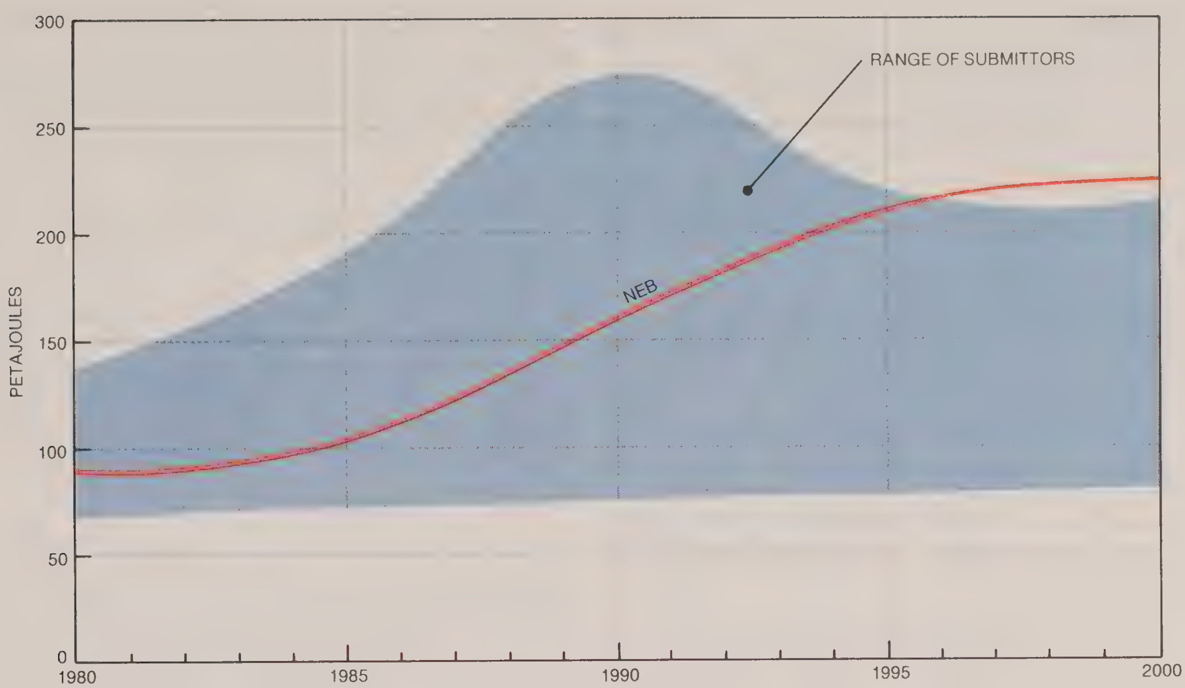

Figure 7-10 Demand for LPG
Comparison of Forecasts

Submittors forecast ethane-based ethylene capacity in the light of forecasts of domestic plus export demand for ethylene coupled with estimates of ethylene production to be based on alternate feedstocks such as naphtha, propane and butanes.

Currently, ethane is used as a feedstock for ethylene production in Alberta Gas Ethylene's world-scale plant at Joffre, Alberta. Imperial expected four additional world-scale ethylene plants using ethane as a feedstock by 1990, while Shell expected three additional plants. Dome, NOVA and TCPL anticipated two additional plants. These assumptions mainly explain forecasts of ethane demand given in Table 7-29.

NOVA, Petrosar and Union Carbide submitted estimates of domestic demand plus exports for ethylene. Demand for ethylene was determined by estimating demand for ethylene derivatives such as polyethylene, ethylene oxide, ethylene dichloride and ethylbenzene and then applying estimates of ethylene requirements per unit of derivative production.

NOVA estimated demand for ethylene to increase from 1.2 kilotonnes in 1980 to 4.7 kilotonnes in 2000 for an average annual rate of increase of 7 percent over the forecast period. Petrosar and Union Carbide projected average annual rates of growth in ethylene demand to be 5.5 percent and 6.5 percent, respectively, over the forecast period.

Table 7-29

DEMAND FOR ETHANE - CANADA
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000
Dome	28	86	134	128	128
Imperial	36	62	98	130	164
NOVA	39	101	138	138	138
Shell(1)	35	35	140	140	140
TCPL	30	75	115	120	120
NEB	39	101	135	135	135

(1) Supplemental Forecast

Views of the Board

The Board's forecast of demand for ethane is based on the expectation that two additional ethylene plants, each producing 680 kilotonnes per year of ethylene and using ethane as feedstock, will come on stream before 1990. The forecast is in conformity with evidence of most Submittors. The Board's forecast is compared with Submittors' forecasts in Tables 7-29 and 7-30 and Figure 7-11.

Table 7-30

DEMAND FOR ETHANE - CANADA
GROWTH RATES
Comparison of Forecasts
(Percent per Annum)

	1980-1990	1990-2000	1980-2000
Dome	16.9	–0.5	7.9
Imperial	10.5	5.3	7.9
NOVA	13.5	0.0	6.5
Shell[1]	14.9	0.0	7.2
TCPL	14.4	0.4	7.2
NEB	13.2	0.0	6.4

[1] Supplemental Forecast

The Board's estimates of domestic demand plus export for ethylene are based on its projections of demand for ethylene derivatives. The Board forecasts ethylene demand to increase at an average annual rate of 6.6 percent over the forecast period.

7.7 Demand for Coal

Introduction

As recently as thirty years ago, coal supplied over 50 percent of Canada's demand for energy. By 1979, however, its share had slipped to about nine percent, as Canada used about 871 petajoules of coal energy, with approximately 70 percent used for generating electricity, 23 percent for making coke and coke-oven gas, and seven percent for other industrial uses.

Views of Submittors

The Board received twenty-two submissions concerning the demand for coal, most of which were limited to certain regions or particular segments of the coal market. Eight submissions contained forecasts of coal demand for Canada covering the period 1980 to 2000. These forecasts are summarized in Table 7-31. Average annual increases underlying these forecasts are shown in Table 7-32.

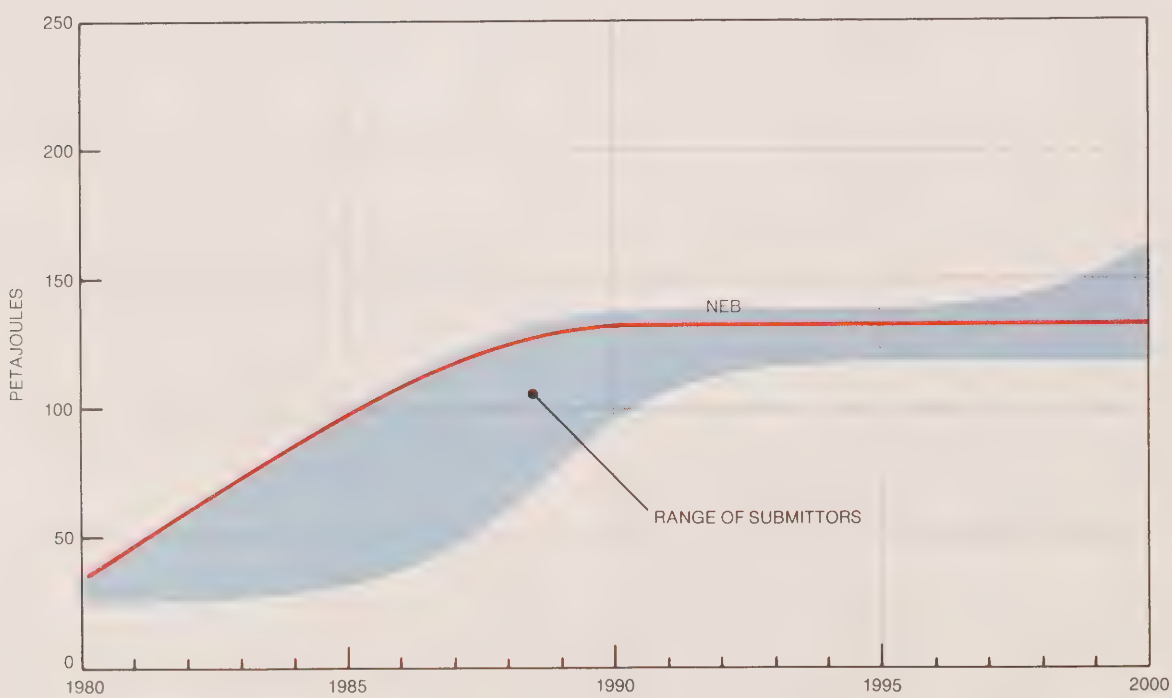

Figure 7-11 Demand for Ethane
Comparison of Forecasts

Table 7-31

DEMAND FOR COAL - CANADA
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000
CPA	915	—	1 396	—	—
Coal Assn.[1]	1 027	1 198	1 709	2 414	3 153
Gulf[1]	856	1 230	1 494	1 922	2 415
Imperial	993	1 151	1 409	1 696	2 129
Norcen[1]	980	1 143	1 284	1 455	1 643
Petro-Canada[1]	871	1 124	1 442	1 729	2 060
Shell[1]	891	979	1 083	1 164	1 268
Texaco	988	1 161	1 329	1 534	1 767
NEB	1 019	1 145	1 337	1 711	2 051

[1] Supplemental Forecast

Table 7-32

DEMAND FOR COAL - CANADA
GROWTH RATES
Comparison of Forecasts
(Percent per Annum)

	1980-1990	1990-2000	1980-2000
CPA	4.3	—	—
Coal Assn.[1]	5.2	6.3	5.8
Gulf[1]	5.7	4.9	5.3
Imperial	3.5	4.2	3.9
Norcen[1]	2.8	2.5	2.6
Petro-Canada[1]	5.1	3.6	4.4
Shell[1]	2.0	1.6	1.8
Texaco	3.0	2.9	2.9
NEB	2.8	4.4	3.6

[1] Supplemental Forecast

For 1980, forecasts of coal demand varied from a low of 856 petajoules by Gulf to a high of 1 027 petajoules by Coal Assn. For the year 2000, the range was still wider, from Shell's forecast 1 268 petajoules, 9.3 percent of its forecast total primary energy demand, to the Coal Assn.'s forecast 3 153 petajoules, 18.3 percent of its forecast total primary energy demand.

Shell, mainly because of its assumptions on economic conditions, forecast a much lower primary energy demand. Shell also expected electricity rates to increase in line with oil and natural gas prices. This would have the effect of moderating the demand for electricity, the largest use for coal. Consequently Shell's forecast of coal required for generation of electricity in 2000, amounted to only 824 petajoules compared to the Coal Assn.'s 2 224 petajoules. Moreover, Shell did not allow for any coal demand for such uses as liquefaction, synthetic gas and steam raising for heavy oil and oil sands production, whereas the Coal Assn. forecast a demand of 399 petajoules for these uses for the year 2000.

Gulf, Imperial, and Petro-Canada forecast the share of coal to be about 14 percent of total primary energy demand by the end of the century. Texaco and Norcen expected it to be about 11 percent.

Coal Demand for Electricity

About 15 percent of Canada's electrical energy is provided by coal-fired stations. Over the next 20 years almost all Submittors forecast a substantial increase in the use of coal for generating electricity and expected oil-fired plants to convert to coal. Their forecasts are presented in Tables 7-33 and 7-34. During the forecast period, the use of coal for generating electricity was expected by Submittors to more than double in Saskatchewan and Nova Scotia and increase by about 50 percent in Ontario and New Brunswick. The most dramatic increase would occur in Alberta which was expected to generate some 90 percent of its electrical needs from coal.

Demand for Coking and Other Uses of Coal

Consumption of coking coal was forecast to grow between 1980 and 2000 at an average annual rate of between 1.4 percent by Petro-Canada and 3 percent by Gulf. Submittors' forecasts were based on the underlying trend in steel demand, the bulk of which arises in Ontario.

Submittors differed widely on the extent of the expected increase in demand for industrial steam coal over the forecast period. Much of the disagreement centered on the extent of the use of coal for liquefaction, synthetic gas and as supplementary fuel for the production of heavy oil and production from oil sands.

The majority of Submittors expected natural gas rather than coal to be the fuel used in heavy oil and oil sands production. As to the demand for coal in other industrial uses, Submittors expected coal prices to increase at a lower rate then the price of other hydrocarbons. Therefore the share of coal used in the industrial sector was forecast to increase, although the rate of growth was expected to be held down by handling and cleanup problems.

A comparison of Submittors' forecasts for industrial steam and coking coal is presented in Tables 7-35 and 7-36.

Views of the Board

The Board's forecast is compared with the range of Submittors' forecasts on Figures 7-12 to 7-14 and Tables 7-31 to 7-36.

The Board's forecast of total coal demand has been derived from separate forecasts of coal demand for electricity generation and for industrial steam and the making of coke and coke-oven gas. The demand for coal in Canada is expected to about double from its 1980 level of 1 019 petajoules to 2 051 petajoules over the next twenty years, a growth rate of 3.6 percent annually.

Table 7-33

DEMAND FOR COAL FOR ELECTRICITY GENERATION - CANADA
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000
CPA	—	—	958	—	—
Coal Assn.[1]	701	851	1 188	1 691	2 224
Gulf[1]	577	903	1 108	1 466	1 880
Imperial	721	844	1 046	1 296	1 640
Norcen	709	881	1 022	1 189	1 379
Petro-Canada[1]	581	806	1 096	1 363	1 666
Shell[1]	599	616	694	746	824
Texaco	709	874	1 026	1 210	1 420
NEB	732	822	990	1 341	1 646

[1] Supplemental Forecast

Table 7-34

DEMAND FOR COAL FOR ELECTRICITY GENERATION - CANADA GROWTH RATES
Comparison of Forecasts
(Percent per Annum)

	1980-1990	1990-2000	1980-2000
Coal Assn.[1]	5.4	6.5	5.9
Gulf[1]	6.7	5.4	6.1
Imperial	3.8	4.6	4.2
Norcen	3.7	3.0	3.4
Petro-Canada[1]	6.6	4.3	5.4
Shell[1]	1.5	1.7	1.6
Texaco	3.8	3.3	3.5
NEB	3.1	5.2	4.1

[1] Supplemental Forecast

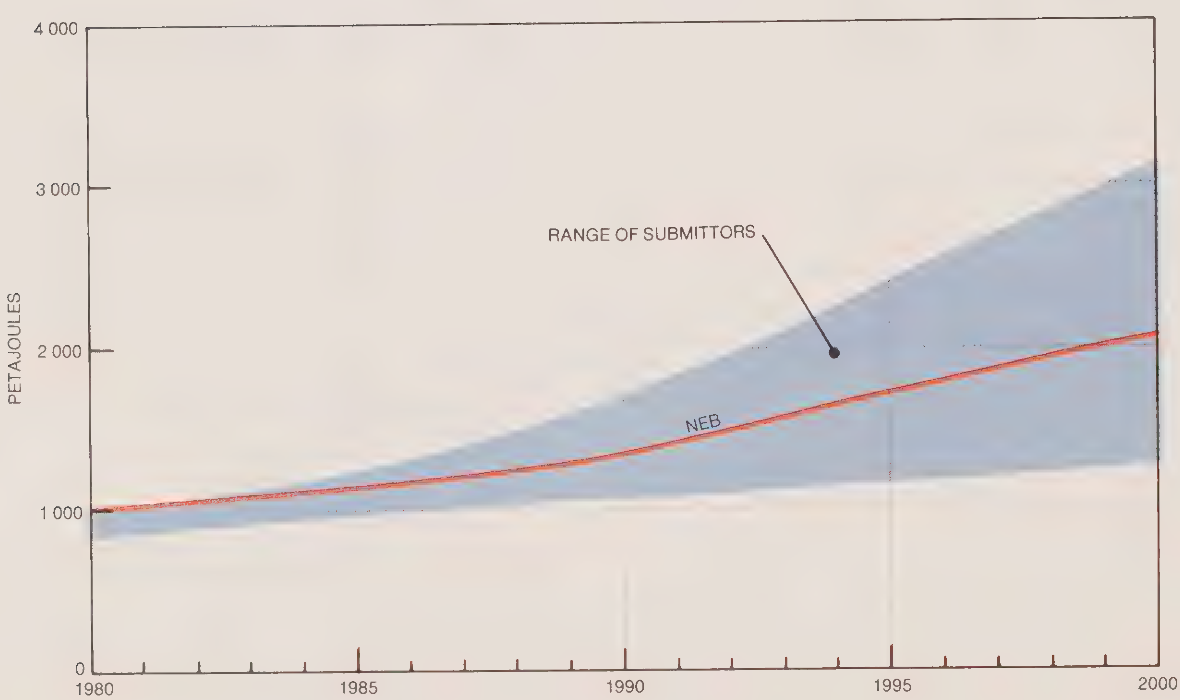

Figure 7-12 Total Demand for Coal
Comparison of Forecasts

Table 7-35

DEMAND FOR INDUSTRIAL STEAM AND COKING COAL - CANADA
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000
CPA	—	—	439	—	—
Coal Assn.[1]	326	347	520	723	929
Gulf[1]	262	311	369	440	518
Imperial	272	307	352	400	445
Norcen	274	284	300	321	345
Petro-Canada[1]	283	312	339	361	386
Shell[1]	278	347	372	400	424
Texaco	274	283	300	321	345
NEB	277	313	335	357	389

[1] Supplemental Forecast

Table 7-36

DEMAND FOR INDUSTRIAL STEAM AND COKING COAL - CANADA
GROWTH RATES
Comparison of Forecasts
(Percent per Annum)

	1980-1990	1990-2000	1980-2000
Coal Assn.[1]	4.8	6.0	5.4
Gulf[1]	3.5	3.4	3.5
Imperial	2.6	2.4	2.5
Norcen	0.9	1.4	1.2
Petro-Canada[1]	1.8	1.3	1.6
Shell[1]	2.9	1.3	2.1
Texaco	0.9	1.4	1.2
NEB	1.9	1.5	1.7

[1] Supplemental Forecast

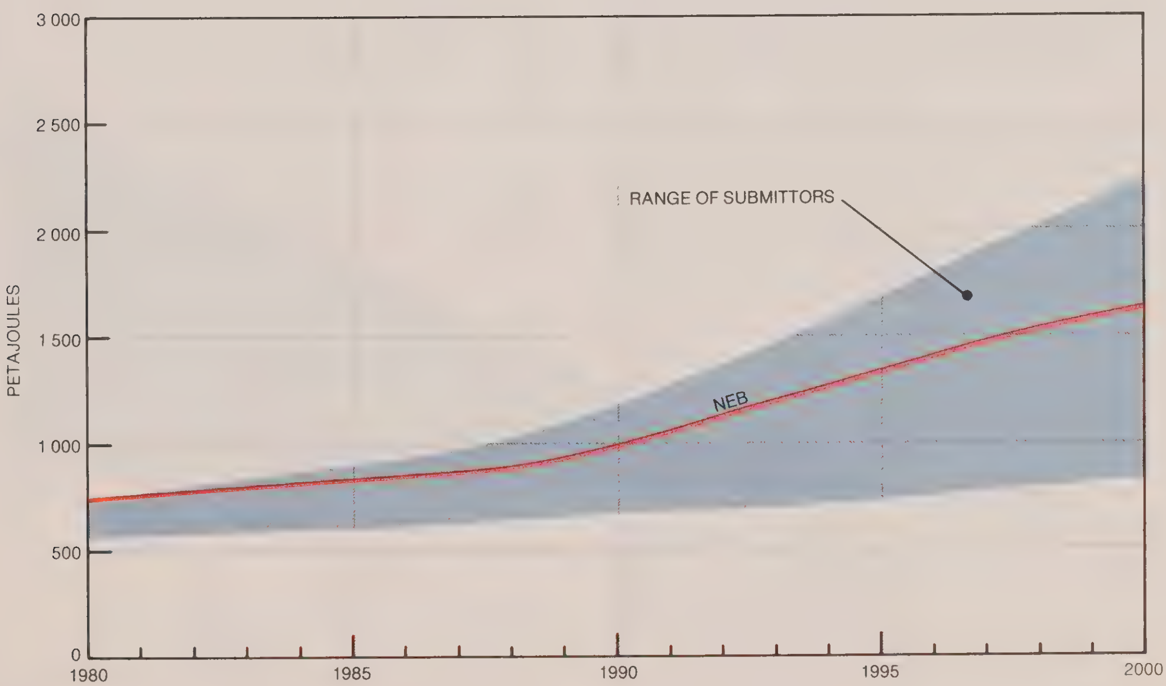

Figure 7-13 Demand for Coal for Electricity Generation
Comparison of Forecasts

The Board forecasts that coal demand for electricity generation will grow at an annual rate of some 4.1 percent over the next twenty years and more than double from its present level of 732 petajoules to 1 646 petajoules in 2000. The coal demand for electricity generation is presented in Figure 7-13.

By 2000, about one-quarter of total electricity in Canada is expected to be generated from coal. Provinces which are rich in coal deposits are expected to use more of this resource to produce electricity. Both Alberta and Nova Scotia are forecast to produce about 85 percent of their electricity from coal by 2000. British Columbia does not generate electricity from coal at present but by 2000 some 23 percent of its electricity is forecast to come from coal. Over the same period, the quantity of coal used for electricity in Saskatchewan is expected to double.

Québec and Manitoba have access to more competitive sources of energy such as hydro and natural gas and are not expected to use any coal for the generation of electricity. Distance to markets and environmental considerations would constrain the use of coal for generation of electricity in other provinces and the territories. In total, by 2000, electricity generation is expected to account for some 80 percent of the total coal demand in Canada.

The Board forecasts that coal demand for purposes other than electricity generation will grow at 1.7 percent per year, from 277 petajoules in 1980, to 389 petajoules by the end of the century. The bulk of this demand will be for coking coal used by the iron and steel industry to produce coke and coke-oven gas. By 2000, the demand for coking coal would amount to about 17 percent of the total coal demand in Canada. The demand for industrial steam coal is expected to grow over the next twenty years. The Board's forecast of demand for coal, other than for electricity generation, is presented in Figure 7-14.

Unlike some Submittors who included large quantities of coal demand for liquefaction, synthetic gas and for steam raising of oil sands and heavy oil; the Board believes that natural gas pricing policy will constrain the use of coal for these purposes.

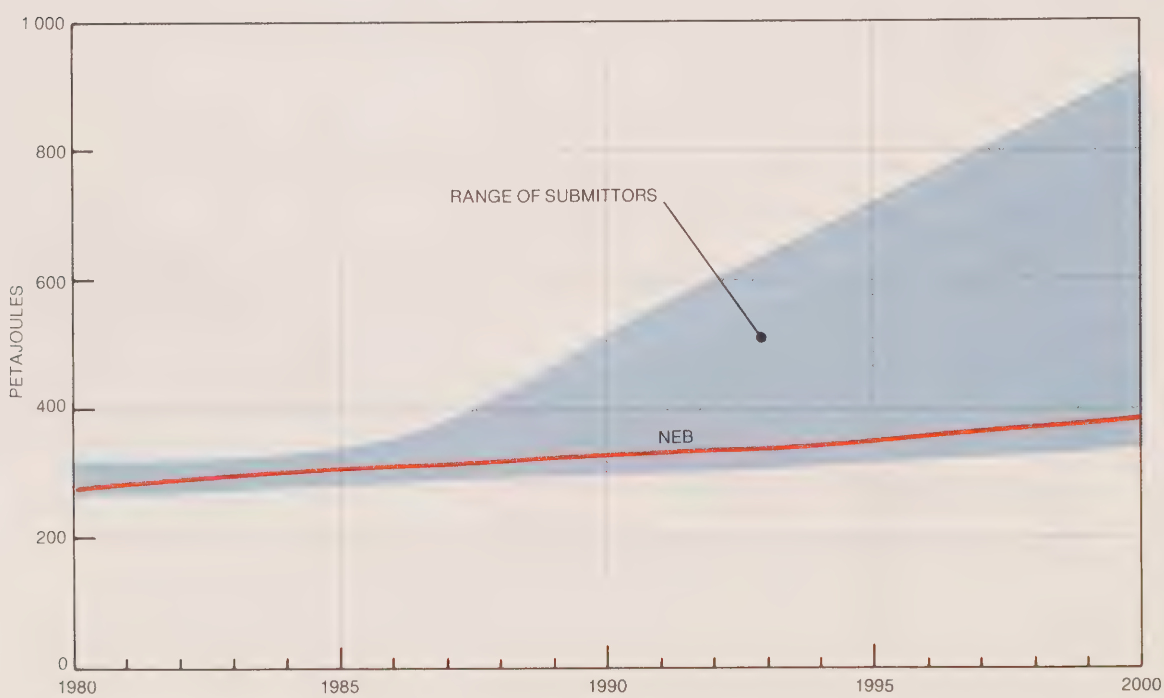

Figure 7-14 Industrial Steam and Coking Coal Demand Comparison of Forecasts

7.8 Demand for Hog Fuel and Pulping Liquor

Views of Submittors

Hog fuel (wood wastes) and pulping liquor are consumed only within the forest products industry. Pulping liquor is a major source of energy for pulp mills and is consumed within pulp mills, but unlike wood wastes, there is little inter-mill transfer.

Forecasts of demand for hog fuel and pulping liquor for total Canada were submitted by Gulf, Imperial, Shell, Texaco and CPA and are compared with the Board's forecast in Table 7-37. Shell's forecast included only Québec, Ontario and British Columbia. As a result of increases in the prices of natural gas and oil products, as well as technological developments in boilers designed to use wood wastes more efficiently, the demand for hog fuel and pulping liquor was forecast to increase substantially.

Table 7-37

DEMAND FOR HOG FUEL AND PULPING LIQUOR - CANADA
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000
CPA	315	—	443	—	—
Gulf(1)	303	347	403	472	570
Imperial	317	369	442	527	579
Shell(1)(2)	201	250	277	292	324
Texaco	332	405	484	540	613
NEB	318	381	448	507	568

(1) Supplemental Forecast
(2) Includes Québec, Ontario and British Columbia only.

Table 7-38

DEMAND FOR HOG FUEL AND PULPING LIQUOR - CANADA
GROWTH RATES
Comparison of Forecasts
(Percent Per Annum)

	1980 - 1990	1990 - 2000	1980 - 2000
CPA	3.5	—	—
Gulf(1)	2.9	3.5	3.2
Imperial	3.4	2.7	3.1
Shell(1)(2)	3.3	1.6	2.4
Texaco	3.8	2.4	3.1
NEB	3.5	2.4	2.9

(1) Supplemental Forecast
(2) Includes Québec, Ontario and British Columbia only.

Over the forecast period, projected average annual increases in the demand for hog fuel and pulping liquor ranged from a low of 2.4 percent by Shell to a high of 3.2 percent by Gulf as shown in Table 7-38.

Variations in the Submittors' forecasts of the demand for hog fuel and pulping liquor were relatively small, with the exception of the partial forecast made by Shell, which Shell stated could be on the low side.

Wood wastes were expected by the Council of Forest Industries of British Columbia, and a number of other Submittors, to make substantial inroads into existing natural gas and heavy fuel oil markets in the forest products industry. In the lumber and plywood sectors, wood wastes were expected to compete with light fuel oil, natural gas and propane. British Columbia forecast hog fuel to take some market share away from oil. New Brunswick, among others, indicated that hog fuel would be used in increasing volumes in the pulp and paper sector.

The share of hog fuel and pulping liquor of total primary energy demand was projected to increase by most of the Submittors.

Views of The Board

The Board's forecast of demand for hog fuel and pulping liquor is based on expected improvements in boiler technology and relative increases in fossil fuel prices, especially those of oil and natural gas, which are expected to make wood wastes and pulping liquor increasingly more competitive in the forecast period. The Board's forecast is compared with Submittors' forecasts in Tables 7-37 and 7-38 and Figure 7-15.

The consumption of hog fuel and pulping liquor is projected by the Board to increase from 318 petajoules in 1980, to 448 petajoules in 1990, and to 568 petajoules by the year 2000, an average annual growth rate of 2.9 percent between 1980 and 2000. Hog fuel and pulping liquor are expected to provide 3.5 percent of total primary energy by the year 2000, compared to 3.1 percent in 1980.

On a regional basis, most of the consumption of hog fuel and pulping liquor is forecast to be in British Columbia, followed by Québec, Ontario, and the Atlantic region. Consumption in Manitoba, Saskatchewan and Alberta is expected to be relatively small.

As a result of improved competitiveness and availability, the rate of growth in demand for wood wastes and pulping liquor is expected to increase in the 1980s. However, by the end of the 1980s most of the unused supply of wood wastes is expected to be consumed leading to a slower rate of growth in the 1990s.

Increased consumption of hog fuel and pulping liquor is expected to be mainly at the expense of heavy fuel oil, but is also expected to limit, to some extent, the opportunities for natural gas expansion in the forest products industry.

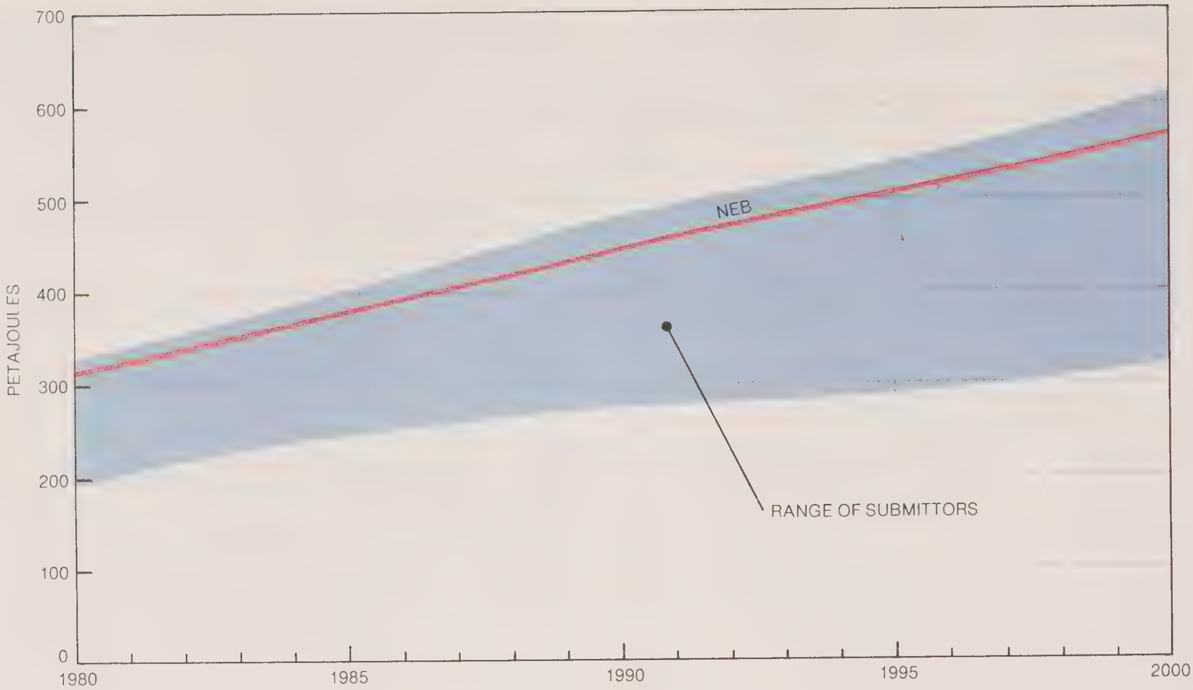

Figure 7-15 Demand for Hog Fuel and Pulping Liquor
Comparison of Forecasts

7.9 Demand for Other Energy Forms

Views of Submittors

The other energy forms included in the Submittors' demand forecasts were renewable energy forms, such as solar and wood. Submittors' forecasts of total Canadian use of these fuels are shown in Table 7-39 and the expected growth rates are compared in Table 7-40. Submittors foresaw average rates of increase over the forecast period that ranged from 8.1 percent per year expected by Shell to 19.2 percent per year anticipated by Texaco.

Gulf, Imperial and Petro-Canada referred to continued use of wood for space heating in the residential sector. Texaco and Imperial expected growing use of renewable energy in the industrial sector, as well as in the residential and commercial sectors.

Submittors expected increased use of solar energy, primarily for low temperature heat. Gulf envisaged that by the year 2000 solar energy would contribute three percent of residential, and nine percent of commercial energy requirements. Petro-Canada expected solar energy to be uneconomical until the late 1980s, but nevertheless predicted increased use of solar energy in the residential and commercial sectors. Shell stated that renewable energy would account for one percent of residential sector energy requirements throughout the forecast period. Further, Shell expected use of solar energy in the commercial sector mostly through the subsidized application of solar energy systems in public buildings.

Table 7-39

DEMAND FOR OTHER RENEWABLE ENERGY - CANADA
Comparison of Forecasts
(Petajoules)

	1980	1985	1990	1995	2000
Gulf[1]	26	27	32	86	158
Imperial	16	17	20	54	155
Petro-Canada[1]	15	57	116	159	195
Shell[1]	12	10	20	33	57
Texaco	8	43	106	164	269
NEB[2]	8	9	87	164	267

(1) Supplemental Forecast.
(2) NEB numbers expressed in terms of fossil-fuel equivalent.

Table 7-40

DEMAND FOR OTHER RENEWABLE ENERGY - CANADA
GROWTH RATES
Comparison of Forecasts
(Percent per Annum)

	1980-1990	1990-2000	1980-2000
Gulf[1]	2.1	17.3	9.4
Imperial	2.3	22.7	12.0
Petro-Canada[1]	22.7	5.3	13.7
Shell[1]	5.2	11.0	8.1
Texaco	29.5	9.8	19.2
NEB[2]	27.0	11.9	19.5

[1] Supplemental Forecast.
[2] NEB numbers expressed in terms of fossil-fuel equivalent.

Several other Submittors discussed the contributions that wood and solar energy could make towards Canada's energy requirements. New Brunswick, Newfoundland, and Nova Scotia noted the use of wood for residential space heating in the Atlantic Region. Other Submittors, for example British Columbia, Ontario, Ontario Hydro, and TCPL, emphasized the present high cost of solar energy systems, but predicted increased use of solar energy, primarily for water heating, after the 1980s. Canadian Solar Industries Association Inc. stated that solar heating systems could become competitive with other systems, if prices for conventional fuels were closer to their replacement costs.

Gulf, Imperial, and Shell projected minor increases in use of renewable energy during the 1980s. Petro-Canada and Texaco predicted that utilization of renewable energy would grow more rapidly between 1980 and 1990 than between 1990 and 2000. Petro-Canada and Texaco expected significant use of renewable energy in the commercial and industrial sectors by 1990.

Views of the Board

Small amounts of renewable energy, other than hydro, are being used in Canada. The Board notes the recent acceleration in the utilization of wood for space heating in the Atlantic region. However, use of wood in Canada is not expected to increase significantly from historical levels.

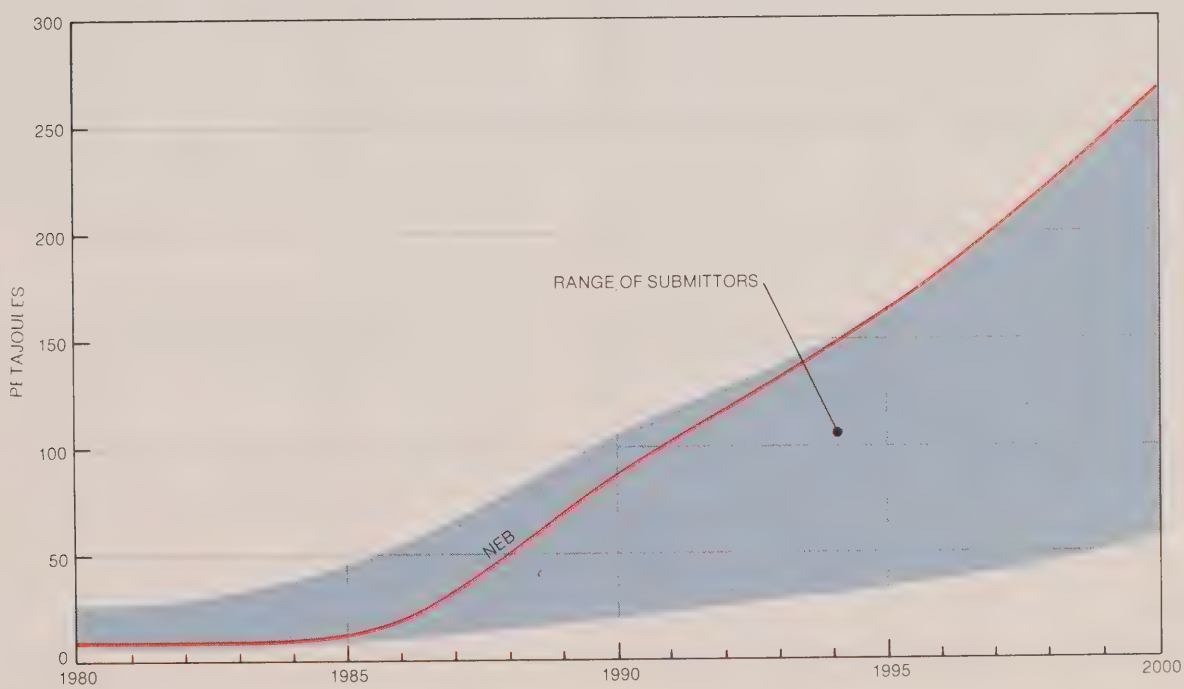

Figure 7-16 Demand for Other Renewable Energy
Comparison of Forecasts

Subsequent to 1985, the Board expects growing use of solar energy in the residential, commercial, and industrial sectors, principally in low temperature applications such as space and water heating.

Although the use of other renewable energy is expected to increase rapidly during the forecast period, from 8 petajoules in 1980 to 267 petajoules in 2000, it is forecast to contribute only approximately four percent of the total energy needs of the residential, commercial, and industrial sectors in that year.

The Board recognizes that energy forms such as hydrogen or biomass other than wood may begin to contribute towards Canada's energy requirements during the forecast period. However, while use of alternative energies is often technically feasible, their economic viability is not expected before the end of the forecast period.

The Board's forecast of demand for other renewable energy is compared with Submittors' forecasts in Tables 7-39 and 7-40 and Figure 7-16.

CHAPTER 8
POTENTIAL CONTRIBUTIONS OF NEW FUELS AND USES

8.1 Introduction

This chapter discusses new fuels which are mostly renewable and are not in widespread use in Canada today. These sources are still in the early stages of development and as such, have not made significant contributions towards national energy requirements in the past. This situation may change in the future as the desired technological developments are achieved and public awareness improves. The fuels considered in this section include alcohols, wood, biomass, solar, geothermal, wave energy, and peat. Hog fuel is discussed in section 7.8 and forecasts of demand for solar and wood are briefly examined in section 7.9.

8.2 Alcohol Fuel

Views of Submittors

Dome stated that it was monitoring many studies being conducted throughout the world on the use of methanol as a motor fuel. The potential use of methanol as a motor fuel was considered to be large and methanol would compete more with propane than gasoline.

The Government of British Columbia stated that it was examining the possibility of using synthetic fuels derived from natural gas, coal or biomass as alternate transportation fuels. It was stated that no unsolvable problems were foreseen in the use of methanol as a transportation fuel but its use in the automobile sector would be hindered if methanol was not used as a vehicle fuel in the United States. This was mainly because of vehicle traffic across the border but it should not inhibit the use of methanol in large scale fleets. With regard to technology, methanol could be produced from natural gas, and, in time, from coal. Methanol production from biomass would not be viable before the mid 1990s.

Gulf stated that the feasibility of moving synthetic fuel, derived from natural gas, out of the Arctic region to both Southern Canada and the United States was being examined. With regard to methanol as a fuel extender, Gulf stated that the potential for market penetration in Canada was relatively limited and that the most obvious market would be the utility companies in the Northeastern United States. The technology for producing gasoline from natural gas is in an elementary stage and Gulf did not feel it would become economically viable before the 1990s.

Imperial stated that any transportation fuel derived from natural gas in Alberta would not be competitive with gasoline unless the price of natural gas was much lower. The use of methanol or other alcohols as extenders to gasoline, up to a level of ten percent, was said to be technically feasible without significant changes to the engine system.

Mobil has developed a new process for converting methanol to high octane unleaded gasoline. One version of the process was said to be ready for commercial use while a more advanced version was about to move from laboratory testing to the pilot plant stage and was expected to be ready for commercial use by 1985.

Mobil indicated that the New Zealand Government had selected the Mobil process for a new complex to produce gasoline from offshore natural gas. The facility which would be operational in late 1985 was expected to produce about 2 200 cubic metres of gasoline per day. Among the projects underway in the United States, there was one of Mobil's which would be producing 6 400 cubic metres of gasoline per day from coal.

Mobil estimated the cost of gasoline produced from methanol to be about 50 U.S. cents per U.S. gallon higher than the wholesale price of gasoline produced from domestic crude oil. This differential was expected to diminish over time and was said to depend on the rate of increase of crude oil prices relative to inflation.

NOVA stated that methanol could either be introduced into gasoline along with the required changes in the gasoline distribution and marketing systems and in automobile carburation or could be converted into gasoline using the Mobil process. The possibility of using methanol with diesel oil was being studied.

Petro-Canada stated that gasohol was not included in the demand forecast; however, the opportunity exists for gasohol to achieve a feasible market share in the next decade. Petro-Canada stated that it has been more costly to produce ethanol than gasoline from crude oil but this situation was changing. It was stated that there were some technical problems with automobile engines with regard to using significant quantitites of gasohol.

Texaco stated that it was in the process of investigating the use of alcohols in Canada and that it believed ethanol to be the most acceptable fuel extender. Alcohol became economic in the United States as a fuel extender because of the subsidy programme. Texaco expressed the view that subsidies should not be used to encourage national objectives, but instead, domestic crude oil prices should be allowed to rise to the world price level, thus making ethanol and methanol economically viable. Texaco stated that it was examining different waste materials which could be converted to ethanol instead of using valuable grains.

Views of the Board

Alcohols can be made from a variety of organic materials. Some of the processes for making alcohols are well developed, such as the production of ethanol from grains, while other technologies are in the development stage, such as the production of ethanol from cellulosic materials.

Alcohols can be used as fuel extenders, fuel replacements, or feedstocks to processes producing synthetic fuels. Although some of the technology for the production of alcohols is well

developed, its use in the existing transportation fleet may present difficulties to its implementation in Canada. In addition, the production of alcohols for use as a transportation fuel may require significant subsidies in order to compete with existing transportation fuels. Therefore there appears to be little likelihood of alcohol capturing a significant share of the transportation market before the year 2000.

8.3 Wood and Biomass

Views of Submittors

Newfoundland stated that wood is used primarily as a fuel in the residential sector and to some extent in rural industry. The increasing costs of oil products and electricity have raised the level of interest in the use of wood as a fuel in industry and it would be further encouraged by future government incentive programmes. Newfoundland estimated that the province could sustain an annual wood yield of 0.85 to 1.1 million cubic metres for use as fuel.

Nova Scotia forecast that biomass energy sources including forest residues, agricultural waste and municipal solid waste could provide the energy equivalent of more than 200 000 cubic metres of oil per year by 1985. Nova Scotia also forecast that the contribution from biomass energy sources in the province would increase from 4.75 petajoules in 1980 to 8.44 petajoules in 2000.

Nova Scotia forecast that agricultural waste has the potential to displace 4 000 cubic metres of oil annually. However, the achievement of this potential was said to depend on success in research, development and demonstration projects now being undertaken.

Nova Scotia estimated that the municipal solid waste from the Halifax and Dartmouth area would have the potential to displace 48 000 cubic metres of oil annually. The technical and financial feasibility of operating small sized plants was being examined.

Nova Scotia stated that the expansion of markets for wood as a fuel in the residential sector beyond 1985 would be limited by the supply of hardwood. The energy contribution from wood in the residential sector was expected to increase from 2.08 petajoules in 1981 to 2.37 petajoules in 2000. In the commercial sector, wood was said to be unsuitable for most large space heating and in the industrial sector, the only renewable fuel used would be waste wood burned by the forest industry in its production process.

Ontario Hydro stated that the forest industry in Ontario has the potential to utilize about 400 000 tonnes of wood waste annually in addition to its present consumption. This wood waste would substitute for more expensive fossil fuels.

If Ontario's target for the use of energy from biomass is to be achieved, Ontario suggested that the principal market would be the industrial sector where it would displace coal and natural gas.

New Brunswick stated that the contribution of energy from wood and wood waste towards total domestic demand was expected to increase from 7.9 percent in 1979 to 12.4 percent in 1985. New Brunswick forecast consumption of wood and wood waste in 1985 to be equivalent to one million cubic metres of oil compared to the potential supply of wood waste in 1985 estimated to be equivalent to 1.6 million cubic metres of oil. Wood has been used in New Brunswick as a fuel in just over one-third of all principal residences and a further expansion in domestic consumption of wood was expected.

British Columbia stated that while the use of plant and animal agricultural wastes was theoretically a potential energy source in the province, the disaggregated nature of the agricultural industry would preclude its extensive future use. British Columbia stated that wood biomass was already a heavily used form of energy in the forest industry and accounted for 62 percent of the industry's energy consumption in 1978. Forest product waste has made up 17 percent of the total energy consumption in the province in recent years. The use of wood biomass would depend upon its price in relation to the price and reliability of supply of other energy alternatives.

British Columbia expected a large component of municipal solid waste garbage and sewage to be used to produce energy, with the conversion processes depending upon the desired end products which could be liquid fuels, solid fuels, electricity or gas. In some areas, there was an opportunity to combine solid waste with mill residues to increase the utilisation by electricity generating plants. It was anticipated that at least one plant would be under construction before 1996.

TransCanada stated that wood waste was contributing significantly to the energy requirements in the forestry sector. TCPL referred to a study by Canadian Resourcecon which foresaw plywood and saw mills using increasing amounts of residue for their own energy needs. The study forecast industrial wood waste consumption to increase from 80.2 petajoules in 1978 to 148.4 petajoules by 2000 in Ontario and the Western Provinces.

Views of the Board

The Board has reviewed the evidence submitted and concludes that, in total, the contribution from wood and biomass in non-hog fuel uses, beyond the current levels, will be minimal in the forecast period.

Although Canada's biomass resource is quite large in terms of forest, crop, livestock, and municipal wastes, many of the proposed systems for harvesting or collecting these materials and turning them into useful energy forms are technologically or economically unproven.

In addition, many of the methods proposed for enhancing the use of the products of biomass in Canada are site-specific and the use of these products is limited in terms of economical distribution. For example, steam generated in a municipal waste disposal system would have relatively few high density areas within which it could be distributed.

8.4 Solar Energy

Views of Submittors

CSIA stated that low temperature active and passive solar systems would be the first solar technologies to gain wide acceptance in the market place. Over the next ten years, low temperature active systems using solar energy were forecast to increase significantly while passive solar heating systems would increase to a lesser extent. This was due to the fact that active solar systems could be applied to existing buildings, whereas passive systems would be applicable for the most part only in new buildings.

CSIA expected the contribution from passive solar systems of about ten petajoules per year to increase to 30 petajoules per year by 2000 as the stock of well designed buildings increased. This projection would be higher if the greenhouse industry developed rapidly. From a recent study, CSIA estimated that active solar systems could provide 100 petajoules per year by the year 2000.

CSIA argued that, like frontier energy resources, solar would require incentives to accelerate the development of the technology. Presently, solar energy is unable to compete with natural gas because of the higher cost of production of solar equipment. It was recommended that the subsidies required to develop this industry should come from the export revenue of non-renewable resources. These incentives should either take the form of a tax credit or a government grant of 50 percent of the cost and a loan for the balance.

For cost effectiveness, CSIA estimated that a solar domestic water heater producing about 8 gigajoules per year should cost between $1 200 and $1 600, but that dealer installed systems were said to cost about $2 500. However, through technological improvements and mass production and marketing, the necessary cost reduction could be achieved. It was anticipated that within the next five years, provided there were reasonable increases in the price of conventional energy, solar heating systems would become competitive without any government subsidies.

British Columbia stated that market penetration of solar heating would not be significant if it was assessed in relation to the current and predicted prices of conventional energy. For the solar option to become feasible, either conventional sources should be priced at marginal cost or incentives should be considered. It would be difficult for significant penetration to occur in the retrofit market without incentives; however, British Columbia expected the penetration rate to increase dramatically in new installations if incentives were provided. British Columbia anticipated the most attractive markets for solar space and hot water heating to be new and retrofit multiplex dwellings and separate hot water systems.

Without significant financial incentives, Ontario suggested that active solar space heating systems would not be cost-effective and that residential space heating using an active solar system was one of the least competitive types of solar systems.

Ontario Hydro stated that the most promising future applications for solar energy in Ontario were in hot water systems and in passive space heating. A system could be envisaged where solar could be used for a lower heating range and another fuel, perhaps electricity, to raise the temperature to useful levels. To harness solar energy using existing technology was forecast to be expensive and the rate of introduction of solar heating in Ontario was said to depend on the incentives supplied by the government.

Petro-Canada stated that the cost of solar powered systems for residential use would remain very high relative to gas and electricity until the late 1980s.

Nova Scotia stated that active solar heating at present was not economical but expected recent technological advances to make it more attractive. By 1985, active and passive solar heating in the residential sector could contribute 0.04 petajoule which would increase to 1.3 petajoules by 2000. In the commercial sector, Nova Scotia expected technological improvements to make solar applications viable by 1985, with a contribution in 1990 estimated to be 0.32 petajoule rising to 0.42 petajoule by 2000, provided the appropriate consumer education and encouragement were given. It was also suggested that solar thermal energy had the potential to displace traditional energy forms in industrial applications.

TCPL stated that very little of Canada's energy requirements were being met by solar systems. However, the potential for solar heating to displace conventional energy sources was considered to be great. The date when solar heating equipment would be available, and economical compared to conventional heating systems would partially depend on government policy. TransCanada stated that solar swimming pool heating systems were economical and that solar water heating was competitive in new dwellings in regions with high electricity costs. Estimated lifecycle costs for conventional and solar systems used for space heating in various types of residential structures suggested that solar systems would not be economical until after the year 2000.

TCPL did not expect solar energy to be used in significant quantities until 1990. It was forecast that during the period 1991 to 2000 there would be a growth in the use of solar energy such that it would supply half the hot water requirements of new households. However, solar systems would not be used for space heating before the year 2000. In the commercial sector, TransCanada concluded there would be no use of solar energy for space or water heating throughout the forecast period. In aggregate, it was forecast that by the year 2000, solar energy consumption in Ontario and the Western Provinces would be 2.4 petajoules or 0.3 percent of total residential energy requirements.

Mr. Breault, representing the City of Medicine Hat, suggested that the entire impetus of the federal government's solar energy research should be located in South East Alberta, and that there were many organizations supporting this concept. He stated that the greenhouse industry was an established solar industry

and that the clay glass industry stood to expand its markets through development of solar energy. South East Alberta was said to be the sunniest spot in Canada receiving over 2 400 sunlight hours per year. Mr. Breault identified several projects which could be part of a proposal for this region, including a large solar energy research station, the application of solar and wind energy for irrigation, the expansion of the greenhouse and glass industries, and the establishment of a viable wine industry.

Views of the Board

The Board is aware of the general public interest in the potential for solar energy. Studies indicate that the potential offered by solar energy even in a country as far north as Canada is quite attractive and there is no doubt that solar energy will play a role in Canada's energy economy. However, considerable uncertainty exists as to when and to what extent solar energy will succeed in making in-roads in the Canadian energy market.

Relative to some other countries, Canada has been slow in developing solar technologies suitable to use in the Canadian climate. Some aspects of solar heating technology remain to be developed and tested. Many regulatory obstacles and institutional barriers must be overcome. Another major hurdle that must be cleared is one of economics. Before a consumer can use solar energy, he must invest a significant amount of money, especially in relation to the capital cost of systems using conventional fuels. With the price of dwellings and mortgage interest rates already quite high, the additional cost of expensive solar heating systems generally places the cost of solar energy outside the financing capability of most Canadians.

The Board recognizes that solar energy could contribute appreciably to Canada's energy supply over the long run, especially in the residential and commercial sectors. However, given the technological uncertainties and high costs associated with such systems, the contribution of solar energy to total energy requirements will be relatively small in the next two decades.

The Board recognizes that major technological developments, significant cost reductions, or government assistance may make this assessment conservative.

8.5 Other Forms of Energy

Views of Submittors

British Columbia stated that no major use of geothermal energy had occurred as yet in the province although the sedimentary basins of northeastern B.C and the volcanic cordillera were expected to contain geothermal resources. However, based on today's limited knowledge of the resource and the application costs, it was estimated that maximum geothermal electricity generation potential in the province was 750 megawatts and potential annual direct use would be about 500 gigajoules. However, reaching these levels would require considerable government involvement and over the forecast period it was unlikely that these levels of application would be realized.

The Government of British Columbia discussed two potential systems for harnessing British Columbia's large wave power resource. However, it was stated that implementation of these systems had major economic and environmental constraints which would have to be overcome if a substantial wave power project was to materialize by 1996. It was concluded that unless incentives were given to undertake major research programmes to develop and apply these wave power systems, production of wave electricity before 1996 would be unlikely.

The Island of Newfoundland was estimated to contain approximately two million hectares of peat lands and as much as 250 million cubic metres of fuel peat. This was equated to the energy from 3.2 to 7.2 million cubic metres of oil. Newfoundland stated that the environmental effects of large peat harvesting in Canada were not yet fully understood and the logistics of managing the resource would pose serious problems. Newfoundland maintained that there was little doubt that peat would contribute increasingly to the energy supply of the province within the next two decades.

Views of the Board

Many potential energy sources such as peat and geothermal are already in use in other parts of the world. However, in Canada it will be necessary to establish the resource base and the economic feasibility of such projects before they can begin to contribute to Canada's energy supply.

For other forms of energy such as fusion, ocean thermal, solar power satellites, wave, and hydrogen and fuel cell systems, the technology has yet to be developed to a sufficient degree to allow for a full assessment of the potential contribution of these sources to meeting Canada's energy requirements.

The Board acknowledges that there is a very good chance that at some time in the future some of these technologies will provide energy to meet Canada's requirements. However, the Board also accepts that it is unlikely without significant economic and/or technological breakthroughs, that these other forms of energy will contribute significantly to Canada's energy needs before the turn of the century.

CHAPTER 9
REQUIREMENTS FOR REFINERY FEEDSTOCKS

9.1 Introduction

The conversion of refined petroleum product demand into estimates of the need by refineries for crude oil or other feedstock is not a simple matching of total volumes. The proportion of total demand for each product, the characteristics and amounts of available feedstocks, the refiners' and marketers' own demands for fuel, and the possibility of exports and imports are some of the considerations required to develop estimates of requirements for refinery feedstocks.

9.2 Requirements for Crude Oil and Equivalent

The schedule of a Canadian refiner's requirement for feedstock is derived essentially from his anticipated sales of refined products, the capacity, type and flexibility of available processing plant and the mix of crude oils and other components available from Canadian and foreign sources. As on previous occasions four companies — Gulf, Imperial, Shell and Texaco — provided detailed estimates of the feedstock requirements of the industry in their original submissions; these are shown in Figure 9-1 to 9-3 and Appendix I.

Subsequent to an invitation by the Board for comments regarding the effects of the NEP on the estimates of refined product demand, forecasts were revised downward to reflect the results of the proposed off-oil measures. Assessments were made by Submittors of the impact of various other elements of the NEP on domestic oil supply, imports and the composition of feedstock streams likely to be available to Canadian refiners.

Views of Submittors

In their original submissions, Gulf, Imperial, Shell and Texaco differed in their estimates by as much as 29 percent or about 80 thousand cubic metres per day in respect of total Canadian feedstock requirements in the later part of the forecast period. The differences resulted principally from variances in estimates of refined product demand. There was a much closer agreement

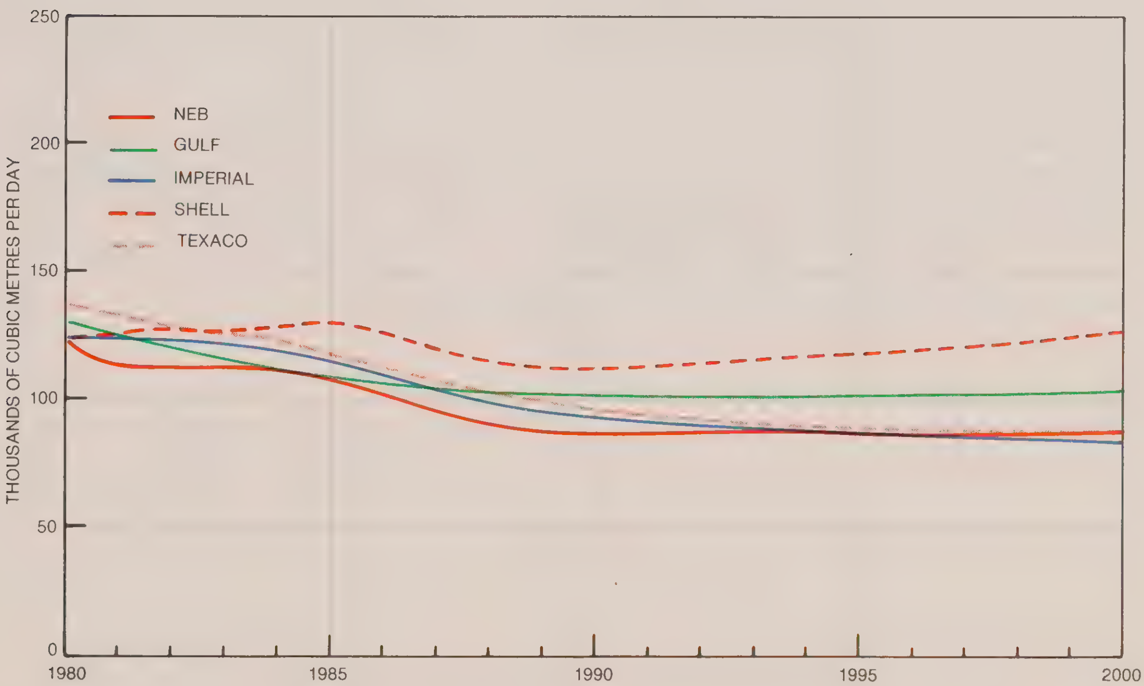

Figure 9-1 Requirements for Refinery Feedstocks (Crude Oil & Equivalent) Québec and East Comparison of Forecasts

between companies in their post-NEP estimates. All four envisaged substantial decline in Canada's current requirements for refinery feedstocks. The 1980 level for the country as a whole will not be recovered by the year 2000 according to most of the revised forecasts, which reflect some of the intended impact of the off-oil objective of the NEP.

Québec and East

Refined product imports into Eastern Canada were forecast to remain constant by most companies. Texaco, however, forecast a rise from 2 000 cubic metres per day in 1980 to 15 000 cubic metres per day by 2000. This was based on the assumption that greater imports of refined products would be available from OPEC countries. Product exports, mainly heavy fuel oil, were expected to drop off steadily from present levels until their virtual cessation in the 1990s. This conclusion was related by most Submittors to assumptions regarding heavy fuel oil upgrading in Eastern Canada and by some Submittors to the expectation of lighter feedstock streams eventually becoming available from domestic sources.

In total, feedstock requirements in the area of Québec and East were forecast by companies to decline from about 125 thousand cubic metres per day in 1980 to between 84 thousand cubic metres per day according to Imperial, and 106 thousand cubic metres per day in Gulf's view, in 2000. This would correspond to an average annual rate of decline of between 0.9 and 2.0 percent over the forecast period.

Ontario and West

The Submittors forecast continuing imports of refined products into British Columbia, related to an absence of refinery expansion on the West Coast. With the exception of Shell, product exports were forecast to decline sharply from their present level of 5 to 10 thousand cubic metres per day with the installation of heavy fuel oil upgrading facilities in Ontario and Alberta.

In contrast with the situation outlined above for Québec and East, the demand for crude oil and equivalent was foreseen by Submittors to remain substantially stable at the 1980 level of about 180 thousand cubic metres per day.

Views of the Board

The Board's forecast of requirements for refinery feedstocks based on the middle case demand for oil products as shown in Chapter 7 is shown along with other Submittors in Figures 9-1 to

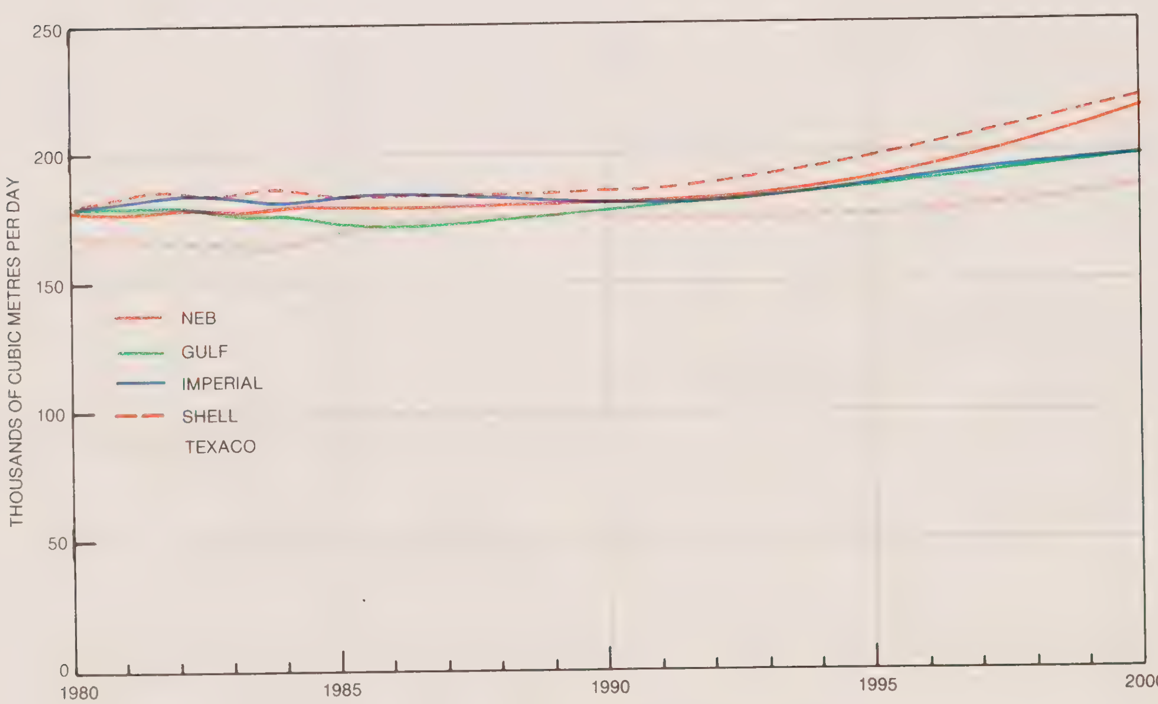

Figure 9-2 Requirements for Refinery Feedstocks (Crude Oil & Equivalent) Ontario and West Comparison of Forecasts

9-3. Supporting data is contained in Appendix I. The Board's forecast of Canadian feedstock requirements to meet domestic product demand is at the low end of the range of estimates made by the four companies for the first ten years of the forecast period. From 1995 onwards, however, the Board's estimates tend to exceed those of the Submittors; this is particularly true for the requirements of Ontario and West.

Québec and East

The Board is in agreement with Submittors that Eastern Canada will see an actual decline in requirements. It estimates this reduction at approximately 35 thousand cubic metres per day over the forecast period, equivalent to an average annual decrease of 1.6 percent. This will lead to significant spare distillation capacity which could result in the withdrawal from service of inefficient units.

One of the more significant features of feedstock supply in the early part of the forecast period is its increasingly heavy nature, because of the anticipated declining availability of light crude oils in domestic and import streams. In view of this, and a decreasing demand for heavy fuel oil, the Board forecasts a growing surplus of heavy fuel oil in Eastern Canada until 1986, when upgrading capacity of 12 to 15 thousand cubic metres per day is assumed to come on stream in Montreal.

In the absence of upgrading facilities, other options could be adopted to minimize the production of heavy fuel oil including modification to the oil import compensation program, exports, closure of refineries and reductions in refinery runs with corresponding imports of light products. It must be recognized that, although in the longer term there may be improvement of feedstock quality resulting from the advent of synthetic, frontier or even offshore supplies, the general trend will be towards heavier streams.

The Board's forecast assumes only minor imports of refined products.

Ontario and West

In the Board's forecast, feedstock requirements in the area Ontario and West remain relatively constant between 1980 and 1985 at about 177 thousand cubic metres per day and then increase to 190 thousand cubic metres per day by 1995 and 217 thousand cubic metres per day in 2000. This would corre-

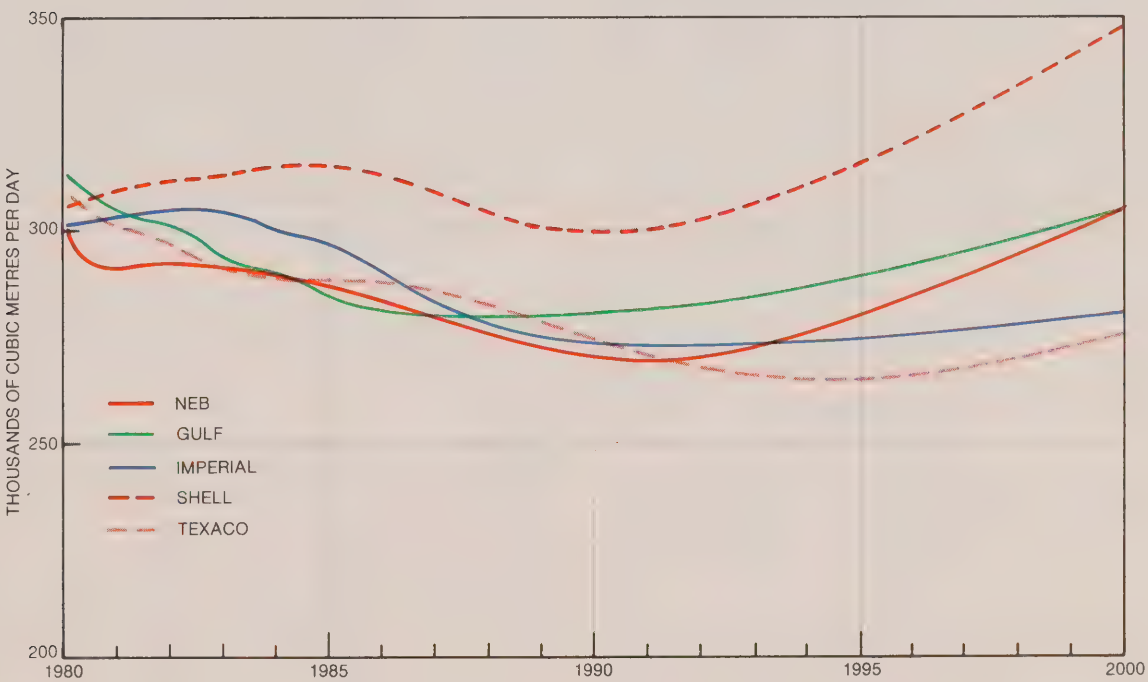

Figure 9-3 Requirements for Refinery Feedstocks (Crude Oil & Equivalent) Canada Comparison of Forecasts

spond to a somewhat higher rate of growth than that postulated by most of the Submittors, averaging about one percent per annum.

It was assumed that the requirements for refinery feedstocks in the Prairies and British Columbia would be met from domestic sources throughout the forecast period.

In Ontario, refineries would be run basically to meet provincial demand. These refineries are faced with higher sulphur levels because of changing crude streams and it is assumed that heavy fuel oil surpluses would continue until the announced upgrading units commence operations in 1985. Heavy fuel oil surpluses could also be expected to lessen or disappear in the Prairies from 1983 on.

It is in the Prairie Provinces that the Board foresees most of the increase in crude requirements taking place in order to satisfy increasing light product demand in British Columbia as well as in the Prairies.

9.3 Requirements for Indigenous Heavy Crude Oil

Forecasts of requirements for indigenous heavy crude oil were submitted by Gulf, Imperial, Petro-Canada, Shell and Texaco. Most Submittors stated that domestic demand for indigenous heavy crude is seasonal and primarily a function of the demand for asphalt. Processing of indigenous heavy crude oil for the manufacture of refined products other than asphalt is currently limited by available process equipment. The outlook is for decreasing supply of light crude oils, whether indigenous or foreign, and refiners must contemplate their replacement by heavier feedstocks. The extent to which this replacement is made in terms of indigenous supply may depend, in large measure, on relative prices and government policies.

Appendix J sets out the Board's definition of heavy crude oil.

Views of Submittors

Ontario and West

The requirements Ontario and West for indigenous heavy crude oil anticipated by Submittors varied substantially after 1985, and are summarized in Table 9-1.

It was generally assumed that requirements for indigenous heavy crude oil were tied to asphalt demand, except for Midale crude which is non-asphaltic and provides both heavy fuel and coker feedstocks in Ontario. Shell, being the main processor, did not provide an estimate of the use of Midale crude. Gulf forecast demand for this crude at 6.1 thousand cubic metres per day in 1980 rising to 7.0 thousand cubic metres per day by the year 2000. Imperial confirmed that it would continue to use heavy crude oil as a source of coker feedstock at its Sarnia refinery. Imperial further stated that its demand forecasts had included assumptions on the increased use of heavy crude oil and reduced heavy fuel oil production resulting from installation of a variety of refinery upgrading facilities between 1980 and 1985 such as those announced by Petrosar, Sunoco and Imperial.

Québec and East

Table 9-2 summarizes the forecasts of Submittors with respect to the requirements Québec and East for indigenous heavy crude oil. Husky forecast that the Sarnia/Montreal section of the Interprovincial Pipe Line would be reversed in the mid-1980s and therefore access to the market in the area Québec and East for indigenous heavy crude oil would disappear. In the short to medium term, however, until completion of the heavy crude oil upgrading facilities that Husky contemplates building in Western Canada, the company contended that the processing of Mexican heavy crude oil by eastern refiners would adversely affect the use of indigenous heavy crude oil. Texaco, on the other hand, testified that importation of Mexican crude has the effect of backing-out traditional offshore heavy crudes.

Table 9-1

ONTARIO AND WEST REQUIREMENTS FOR INDIGENOUS HEAVY CRUDE OIL
Comparison of Forecasts
(10^3 m^3/d)

	Gulf	Imperial	Petro-Canada	Shell	Texaco	NEB
1979	12.0	12	12	12.7	18	12.0
1980	19.6	13	13	13.5	19	13.1
1981	20.0	22	13	14.0	19	15.0
1982	20.6	29	14	14.3	20	15.3
1983	21.3	31	15	14.6	21	15.8
1984	22.2	31	15	14.9	21	16.4
1985	22.9	34	16	15.3	22	17.0
1990	25.9	23(1)	20	17.5	27	19.7
1995	28.9	11(1)	20	19.1	23	22.7
2000	31.7	14(1)	20	20.0	21	26.4

(1) Constrained by supply availability

Table 9-2

QUEBEC AND EAST REQUIREMENTS FOR INDIGENOUS HEAVY CRUDE OIL
Comparison of Forecasts
(10^3 m^3/d)

	Gulf	Imperial	Petro-Canada	Shell	Texaco	NEB
1979	4.7	5	5	4.8	3	4.7
1980	6.0	6	7	4.9	3	8.0(2)
1981	5.4	9	7	5.1	3	6.6
1982	5.6	10	7	5.2	3	8.8
1983	5.7	11	7	5.4	3	9.1
1984	5.9	10	7	6.4	3	9.3
1985	6.0	9	7	7.9	3	9.6
1990	7.3	12(1)	10	7.9	—	10.6
1995	8.7	5(1)	10	7.9	—	12.0
2000	10.3	—(1)	10	5.9	—	13.8

(1) Constrained by supply availability.
(2) Includes heavy crude oil exchanges.

Imperial assumed that with the decline in the availability of light crude oil, the use of indigenous heavy crude oil would correspondingly increase to make up the shortfall. Both Petro-Canada and Shell shared similar views stating that this would result in the production of increased volumes of heavy fuel oil.

Views of the Board

Ontario and West

The Board's approach to forecasting requirements in Ontario and West for indigenous heavy crude oil remains unchanged from that used in previous reports. Basically, asphalt demand determines the quantity of heavy crude oil required. The yield of asphalt from heavy crude oil is assumed to be 1 cubic metre of asphalt for every 2.2 cubic metres of heavy crude processed.

The Board has also included in its forecast a continuing requirement of some 4.2 thousand cubic metres per day of indigenous heavy crude oil to manufacture products other than asphalt.

The Board's forecast of Ontario and West requirements excludes feedstock for any facility designed to upgrade heavy crude oil in Western Canada.

Québec and East

In estimating the future demand for indigenous heavy crude in Québec, the Board has relied on the testimony provided at the inquiry and its own-short term forecasts for 1981 and 1982. The evidence indicated that asphalt production in Québec would probably be met from the use of both indigenous and imported heavy crude oil; accordingly, the use of indigenous heavy crude oil after 1982 has been assumed to increase in proportion to the Board's estimate of asphalt demand in Québec.

9.3.1 *Prospects for Heavy Crude Oil Upgrading*

Introduction

This section deals with matters related to the construction of a facility in Western Canada to convert domestic heavy crude oil into a light synthetic feedstock suitable for use at existing Canadian refineries. A crude oil upgrading plant or upgrader is primarily referred to in regard to processing of crude oil from the Lloydminster area of Alberta and Saskatchewan, however, heavy crude oil from other areas such as Cold Lake could also provide raw material for it. Readers are cautioned to distinguish between heavy crude oil upgrading in Western Canada, upstream of refineries, dealt with in this section and heavy fuel oil upgrading in Ontario and Québec, downstream of refinery distillation processes, dealt with in section 9.4.

Views of Submittors

Husky submitted that upgrading was an integral part of its plan for heavy crude oil development and that design was under way for an upgrader to start up in 1985 assuming an early 1981 decision. The size of the upgrader would depend on oil production rates and technology chosen but indications were that initial capacity would be 4 500 cubic metres per day and that the unit cost of upgrading would be between $55 and $95 per cubic metre. The company indicated that the direct costs of upgrading had been marginally reduced under the NEP but that the most critical factor was the negative impact of the NEP on the production of heavy crude oil and the resulting uncertainty as to the longer term source of feedstock.

Petro-Canada stated that plans should be expedited to build upgrading facilities. The company testified that a plant somewhere in the order of 8 000 cubic metres per day might be justifiable and could be in production by 1985.

Petro-Canada maintained that its two basic concerns with regard to an upgrading facility were the supply of heavy crude oil feedstock and the margin between the prices of heavy and synthetic crude oils. The question of adequate supply was said to be largely dependent on tertiary production of heavy crude and this was causing some concern especially in the longer term. In the short term, however, a considerable volume of heavy crude oil which was being exported could be directed

towards an upgrading facility. The company further stated that a significant portion of present and future heavy oil production was in Saskatchewan where the provincial fiscal regime combined with NEP provisions made much of the existing heavy oil production uneconomic.

On the matter of the economics of upgrading, the company indicated that costs depended largely on the process selected and the size of facility. An 8 000 cubic metre per day plant could cost about $1 billion; operating costs were stated to be about $50 to $65 per cubic metre in "today's" dollars. It was also stated that incentive grants and tax encouragements included in the NEP would assist the economics of an upgrader insofar as they would reduce front-end costs primarily to Canadian but also to non-Canadian investors.

Several other Submittors provided views on heavy crude oil upgrading. It was generally felt that upgrading and development of substantial volumes of tertiary heavy crude oil production went hand-in-hand. A heavy crude oil upgrading plant could solve marketing problems experienced by producers, however, there was considerable doubt on the part of Submittors that under the provisions of the NEP coupled with existing provincial fiscal regimes whether sufficient heavy crude oil supply would be generated to justify construction of such an upgrading plant.

Views of the Board

Objectives of companies regarding the building of facilities for the upgrading of heavy crude oil may not necessarily be coincident with objectives of governments. In circumstances where all available heavy crude oil production could be sold either to Canadian or Canadian and United States refiners, producers would not need to invest in upgrading in order to market their output; consequently an investment in upgrading may not obtain their highest priority. On the other hand, governments may wish to encourage upgrading to satisfy objectives such as improving the security of oil supply.

Heavy Crude Oil Supply Available for Upgrading

The Board concurs with the views of Submittors that an adequate supply of feedstock is a critical factor necessary to justify an upgrading plant. Table 9-3 shows the estimated supply of heavy crude oil for the four oil supply cases developed by the Board and explained in Chapter 10 of this report. The Table also shows the Board's estimate of heavy crude oil requirements and the volume of heavy crude oil that may be available for upgrading. These data suggest that feedstock would be available in sufficient quantities in the period 1985 to 1995 to support an upgrading facility for the high supply and modified base case supply estimates. For the base supply case, heavy crude oil availability is such that there is doubt that a plant would be built and for the low supply case there appears to be insufficient supply.

Economics of Upgrading

In normal economic circumstances, it would be necessary for the cost per cubic metre of heavy crude oil upgrading to be paid for by the difference in the price to the refiner for heavy crude oil and synthetic light crude oil. In present circumstances this difference amounts to between $6 and $15 per cubic metre. In international markets the equivalent difference can be about $65 per cubic metre. With the expected cost of heavy crude oil upgrading in the $60 and $95 per cubic metre range, it is therefore doubtful that these facilities would be built without significant incentives. The Board notes that the design and cost of facilities to upgrade heavy crude oil can vary significantly with both the quality of the input material and the class and quality of the desired product.

The NEP contains provisions that would help support heavy crude oil upgrading. These include incentive grants of 10 or 20 percent of approved costs (depending on Canadian ownership); special tax treatment; and incentive pricing. At present, it is not known how these provisions will affect companies' decisions but the project that seems to have progressed farthest to date is a

Table 9-3

HEAVY CRUDE OIL SUPPLY AND REQUIREMENTS
($10^3 m^3/d$)

	Supply				Requirements			Volume Available for Upgrading			
	Low Case	Base Case	Modified Base Case	High Case	Ontario and West	Montreal	Total	Low Case	Base Case	Modified Base Case	High Case
1981	31.4	31.4	36.5	37.0	15.0	6.6	21.6	9.8	9.8	14.9	15.4
1982	28.6	29.1	36.3	38.3	15.3	8.8	24.1	4.5	5.0	12.2	14.2
1983	29.7	30.7	36.8	40.7	15.8	9.1	24.9	4.8	5.8	11.9	15.8
1984	30.5	31.7	37.0	43.6	16.4	9.3	25.7	4.8	6.0	11.3	17.9
1985	32.6	34.1	38.5	48.7	17.0	9.6	26.6	6.0	7.5	11.9	22.1
1990	36.0	41.5	42.0	65.8	19.7	10.6	30.3	5.7[1]	11.2	11.7	35.5
1995	30.7	39.7	44.4	64.3	22.7	12.0	34.7	(4.0)[1]	5.0[1]	9.7	29.6
2000	23.7	32.6	41.7	53.8	26.4	13.8	40.2	(16.5)[1]	(7.6)[1]	1.5	13.6

[1] If heavy crude oil supply scenarios for each case coincide with the corresponding light crude oil supply, then it would appear that in these instances the Sarnia-Montreal pipeline would have to be reversed thus restricting domestic requirements to those in Ontario and West. Supply less domestic requirements would then be 16.3, 8.0 and (2.7) $10^3 m^3/d$ for 1990, 95 and 2000 for the Low Case and 21.8, 17.0 and 6.2 $10^3 m^3/d$ for 1990, 95 and 2000 for the Base Case.

joint venture including Husky, Saskoil, Gulf, Petro-Canada and Shell. It is the Board's view that if flexibility is exercised in implementation of the NEP, sufficient incentive to investors to proceed with heavy crude oil upgrading could exist.

In assessing future supply of heavy crude oil, and the supply of light crude oil, the Board has assumed that heavy crude oil upgrading capacity is installed as follows:

Low Case Supply--no heavy crude oil upgrading.

Base Case Supply--an 8 000 cubic metre per day upgrading plant starting operation in 1988.

Modified Base Supply--an 8 000 cubic metre per day upgrading plant starting operation in 1986.

High Case Supply--an 8 000 cubic metre per day upgrading plant starting operation in 1986 expanded to 16 000 cubic metres per day in 1990.

The effect of heavy crude oil upgrading is taken into account in the report as a downward adjustment to heavy crude oil supply and an upward adjustment to light crude oil supply. The adjustment is shown in detail in Tables 10-8 to 10-11.

9.4 Refinery Flexibility

In September, 1978, when the Board last reviewed the outlook for oil supply and requirements in Canada, the refining sector described itself as entering a period of adjustment characterized by low demand-growth, over-capacity primarily in Eastern Canada, potential product-mix problems, and the need to adapt to the substitution of natural gas for oil products. On the basis of the submissions for the current review, most of these factors appear to remain, and in certain cases the problems were said to be potentially difficult to resolve, particularly in the short-term.

Views of Submittors

The areas of concern expressed by the industry fall into two broad categories: the ability of refiners to produce the required mix of petroleum products of suitable quality, and the need to modify refineries to upgrade surplus heavy fuel oil.

The major refiners indicated that changes would occur in the proportions of products demanded by the market and some of the companies felt that, as a consequence, product quality problems might be encountered. Imperial said that substitution of natural gas and electricity would accelerate the decline in demand for heating oil and heavy fuel oil. Imperial also forecast that motor gasoline demand would drop in response to higher prices and improvements in automobile efficiency. There would, however, be growing markets for diesel and turbo fuels. The company said that this shift in product demand could place significant stress on refiners. Chevron stated that there would be a significant increase in low-pour distillate demand in Western Canada to meet the requirements of the growing energy and resource development industries. Imperial noted that since there is currently no spare refining capacity in this part of the country, large expansions would be required to satisfy the rising demand.

Shell reported that it had commenced studies to examine the nature of the potential problems that could result from the off-oil program of the NEP. From its preliminary findings, the company felt that refinery capital investments would be needed to deal with two problem areas. First, as a result of the off-oil program, the industry would lose traditional outlets in heating oil markets for high-pour distillate fractions, and the surplus volumes would have to be upgraded or blended into heavy fuel oil. Second, Shell thought that the total distillate demand would not decline as fast as the motor gasoline demand and, as a result, investments designed to maximize the distillate yield would be required. Texaco also expressed the view that the declining gasoline-to-distillate ratio would necessitate refinery adjustments.

Gulf judged that the product quality problem could be substantial until about 1985, when it was expected that a central heavy fuel oil upgrader would be introduced which could be designed to give refiners some flexibility in terms of the gasoline-to-distillate ratio. While Gulf believed that the existing refinery hardware in Toronto and Montreal refineries would be sufficient to handle the current level of synthetic crude oil, it stated that as these volumes increased, refiners would be faced with the difficulty of controlling middle distillate quality. Gulf stated that refinery capital outlays would be required to resolve the quality problem. Imperial believed that the use of cetane and pour improvement additives would generally be needed to improve product quality.

With regard to the heavy fuel oil surplus situation, several Submittors referred to the announced up-grading projects by Petrosar, Ultramar, Suncor and Imperial but said that additional facilities would still be necessary if the substitution of natural gas for oil products were not to be impeded. Murphy/Spur said that to keep surpluses to a minimum, the government should eliminate the payment of compensation on imports of heavy fuel oil. Union Carbide thought that the compensation program should be modified to reflect market-related quality values of each type of crude oil and refined product imported.

Most Submittors maintained that a central upgrader located in Montreal could be an appropriate way of reducing the surplus of heavy fuel oil. In this regard, Petro-Canada stated that it was participating in a feasibility study with Montreal refiners and Soquip, to examine the possibility of constructing such a plant. Petro-Canada hoped that a decision to proceed with the project could be made by mid-year. It further stated that the study group was considering an upgrader with a capacity of 15 to 20 thousand cubic metres per day, and the major refiners estimated that the capital cost of the plant would be in the area of $1.5 billion.

Texaco testified that the economics of a central upgrader were not favourable and that the government had a role to play in the form of taxation incentives. Gulf also felt that a favourable fiscal regime would be needed. Imperial expressed concerns with the economic feasibility, indicating that the project would be marginally successful with heavy fuel oil feedstocks priced at 70 percent of crude oil. The Province of Nova Scotia felt that a joint industry/government approach to the heavy fuel oil problem would be appropriate. Union Carbide said that upgrading

projects would be likely to require assistance comparable with that available to heavy crude oil upgrading investments. In this connection, the company thought that the reference prices available to heavy crude oil projects, as contained in the NEP, could be extended to heavy fuel oil upgrading investments.

Shell, commenting on a central heavy fuel oil upgrader in Montreal, said that several factors needed to be considered before a decision to proceed could be taken. These included the sophistication of equipment and hence relatively high capital cost of the processes necessary to substantially reduce heavy fuel oil production in such a plant, the trend to importation of heavier crude slates in the 1980s which would increase the amount of upgrading required, and the uncertainty of longer term supply of domestic crude feedstocks which could change dramatically if synthetic crude production targets were met. If the synthetic crude oil goals were attained, Shell thought that upgrading processes would be unnecessary or, at best, uneconomic.

Shell questioned whether market incentives alone would be sufficient to attract the large amount of capital required to virtually eliminate heavy fuel oil production in the Montreal area. The company asserted, however, that while upgrading might not be commercially attractive on an industry-alone basis, it could be on a total Canada energy basis given that each barrel of heavy fuel oil upgraded would essentially be equivalent to a one barrel reduction in imported oil. Because there is already a partial market incentive for upgrading, in terms of the spread between light and heavy product prices, any additional incentive required from government would be considerably less than the cost of compensation on imported crude oil. In this regard, Shell stated that about $30 to $45 per cubic metre would be needed and, in the absence of such an incentive, heavy fuel oil upgrading could not be undertaken as a commercial venture.

While Submittors agreed that heavy fuel oil production needed to be reduced significantly and that much of this could be achieved by the mid-1980s, it was felt that there was no option but to continue to export the surplus volumes in the interim period.

Some companies believed that there could be difficulties in selling the surplus product at reasonable prices, depending on the volumes to be exported. In particular, Shell held the view that if export markets were not available, the process of converting domestic markets from heavy fuel oil to natural gas would be awkward and, perhaps, take longer than anticipated. In its revised submission commenting on the impact of the NEP, Imperial said that as a result of its assumed reduction in domestic crude oil supplies, imports, which would likely be of heavier quality, would have to make up the short-fall. The company indicated that the effect of the poorer quality imports and consequent higher yields of heavy fuel oil could result in a need for exports of heavy fuel oil, possibly reaching 30 thousand cubic metres per day in 1985 and 40 thousand cubic metres per day in 1990. The company questioned whether export markets would be available for this quantity of heavy fuel oil.

Views of the Board

The Board has heard considerable evidence at the present and previous hearings about the problems being experienced by the refining industry. These include, among others, surplus capacity in Eastern Canada, a static to declining market for petroleum products coupled with shifts in the proportions of products demanded and, most recently, some difficulty in disposing of surplus heavy fuel oil. With regard to the latter, the Board notes that in an announcement of September, 1980, Gulf cited the surplus heavy fuel oil situation as a factor contributing to the closure of its Point Tupper refinery. In the absence of refinery modifications, there would appear to be some risk of further plant closures in Eastern Canada.

The Board believes that a general shift in the demand for petroleum products has begun and that this trend is likely to continue. The Board is also of the opinion that the refining industry will be operating in an environment of high uncertainty for some time, until decisions have been taken on such major projects as the oil sands, the East coast offshore oil reserves, and the extension of the natural gas pipeline to Québec City and the Maritimes.

The industry appears to be capable of adjusting to the shift in demand for petroleum products and to the potential product quality problems that could arise. It is recognized, however, that refinery investments will be required and that increasing amounts of additives such as pour depressants may be necessary to achieve quality standards. Given that major refinery investments are likely to be required to reduce the production of heavy fuel oil, the industry would seem to have some scope, in terms of designing facilities, to allow for changes in the mix of product demands. In addition, as synthetic crude production levels increase, refiners will likely have to make capital investments to process the larger volumes. Once the equipment is in place, refiners would have some additional flexibility in the gasoline-to-distillate ratio.

The Board believes that the major challenge for refiners in the early to mid-1980s will be to reduce the production of heavy fuel oil. In 1980, exports of heavy fuel oil were about 8 thousand cubic metres per day, including product under long-term licences.

There are a number of factors which, in the short-term, could exacerbate the heavy fuel oil situation. First, there is the possibility of cheap imported heavy fuel oil. Second, the quality of future import feedstocks is likely to become heavier which would result in an increase in the production of heavy fuel oil. Third, there may be insufficient production of domestic crude oil in the early 1980s to maintain capacity on the Sarnia/Montreal pipeline. Any shortfalls would probably have to be replaced by heavier imported crude oils. Fourth, there have been suggestions that refiners in Canada might use increasing volumes of the indigenous heavy crude oil which would also increase the production of heavy fuel oil. Finally, with the NEP encouraging

the substitution of natural gas for oil products, the demand for heavy fuel oil could decline significantly. In this respect, the Board notes that heavy fuel oil demand would be particularly affected in the early 1980s if the extension of the natural gas pipeline to Québec City and the Maritimes were to begin with a large initial volume.

The Board is of the view, therefore, that in the process of meeting its demand for light products during the next few years, the refining industry will continue to produce a sizeable surplus of heavy fuel oil. While it is difficult to predict the magnitude of the surplus, it could be in the order of the 1980 level of exports. To the extent that domestic heavy fuel oil demand falls as a consequence of natural gas penetration and crude slates become heavier, the surplus could be considerably larger than the 1980 level. In view of this possibility, the Board believes that, if gas penetration is not to be impeded, there is little choice but to consider heavy fuel oil exports in the short-term.

From the industry's perspective, decisions on investments in upgrading are complicated by several variables, some of which tend to obviate the need for upgrading. In the period after 1985, for example, some imported crude oil could be replaced by light crude oil from the East Coast offshore. Western Canadian crude oil production could also become lighter as more oil sands plants and heavy crude oil upgraders are constructed. The time when the industry thinks it will begin using these sources, the volume expected from them, together with the continuing pace of natural gas substitution, will be important considerations in the determination of the size and timing of future upgrading investments.

There is also the question of economics. According to Submittors, the capital cost of a central upgrader would be $1.5 billion, or more, for a plant with a capacity of about 15 thousand cubic metres per day. In evaluating investments, refiners would assess whether the costs of converting heavy fuel oil into light products could be recovered by the increase in revenue arising from the sale of the upgraded products. On the evidence, it is questionable whether the costs could be recovered, given current product price levels. In line with the NEP, however, the ratio of natural gas prices to oil prices will decline significantly, thereby providing an incentive for consumers to convert from oil to gas. The effect of this measure, by reducing the domestic demand for heavy fuel oil and therefore its domestic market price, may improve the economics of upgrading investments generally, by widening the differential between light, in particular gasoline and diesel, and heavy product prices. It is expected that the feasibility study on a central upgrader being undertaken by Petro-Canada, Montreal refiners and Soquip will address the economic question in more detail.

The Board is aware that the refining sector has always had to adjust to changing product demands. Despite the uncertainties, in terms of the magnitude of future heavy fuel oil surpluses and the economics of upgrading investments, the Board believes that with sufficient lead time to adjust to longer term trends, the industry has an opportunity, through upgrading, to make a significant contribution toward the goal of achieving oil self-sufficiency.

PART III

DOMESTIC SUPPLY CAPABILITY

CHAPTER 10
SUPPLY OF CRUDE OIL AND EQUIVALENT

10.1 Introduction

This chapter deals with all matters relating to reserves and productive capacity of Canadian crude oil. These are discussed in the following order:

- —established reserves and productive capacity
- —reserves additions, ultimate potential and productive capacity
- —pentanes plus
- —oil sands deposits
- —frontier areas
- —coal liquefaction

Productive capacity from the above categories is summarized in the last section.

Forecasting future oil supply is by nature speculative and subject to widely differing opinions. In arriving at its forecasts, the Board considers four factors as the main determinants of future developments in supply. These factors are geological potential, technological limitations, crude oil prices and government policies. Geological potential is paramount in estimating volumes yet to be discovered, whereas the other factors affect the rate of development and level of recovery. The introduction of the NEP with the October 1980 Federal Budget created a new policy environment which made it more difficult to focus on a most likely forecast of future oil supply.

Because of this, the Board has developed both a base case and a modified base case. As in previous reports, the Board has developed a high and a low case to illustrate the uncertainty surrounding the base cases. The specific assumptions used to develop these four cases, and an explanation thereof, are found in the appropriate sections of the Chapter. However, because of the complex nature of the oil supply forecast, the principal assumptions have been summarized in the Introduction so that the concepts underlying each scenario can be more easily understood.

Base Case: the base case is intended to show the productive capacity the Board would expect if the NEP were implemented without modification and if there were no changes to current provincial policies. The crude oil prices used start in 1981 at $115 per cubic metre for conventional oil, $189 per cubic metre for tertiary recovery oil, and $239 per cubic metre for oil sands. The NEP does not specify a price for frontier oil and no explicit price assumption has been made in the Board's forecast. Rather, the Board has assumed that the price to be set by the Federal Government would be adequate to encourage the development of oil discoveries made in the frontier areas.

The estimates of undiscovered potential in the base case for the conventional and frontier areas are those believed to have the most likely geological probability of occurrence.

Development of the various supply sources is also based on the assumption that there will be continued development in resource extraction, processing and transportation technologies.

Modified Base Case: the modified base case is intended to show the effect that higher producer netbacks would have on oil supply. Several assumptions were changed from the base case, all with the intended result of increasing the economic viability of oil supply projects. To illustrate the effect of a higher producer netback, the tertiary price was increased to $239 per cubic metre for light crude oil and to $260 to $300 per cubic metre for oil sands. It should be noted that in most instances a higher netback could be achieved by means other than price such as reduced taxes and lower royalties.

Low Case: the low case is intended to show a lower limit to the Board's productive capacity forecast. The major assumptions are lower geological potential and reduced producer netback from the base case. The prices used are NEP prices where specified. Where prices have not been specified or the procedures for qualifying for incentives are not defined, the low case uses the least favourable combination of circumstances. It is further assumed that no significant advances to current technology will be made during the forecast period.

High Case: the high case represents the maximum level of supply the Board believes could occur given the most advantageous coincidence of supply conditions. Prices up to the world price are assumed if required. These are assumed to be $300 per cubic metre for light and synthetic crude oil, and $230 per cubic metre for heavy crude oil. High estimates of geological potential are used although considered to be less likely than those used in the other cases. Significant technological progress is anticipated.

Additional information regarding the assumptions underlying the Board's four supply cases is shown in Table 10-1.

10.2 Supply from Conventional Areas

10.2.1 *Established Reserves and Productive Capacity*

Views of Submittors

Submittors were asked to provide forecasts of total supply from remaining established reserves, and to submit data on individual pools of which they were the operator or major interest owner.

Reserves data were submitted on individual pools and on a composite basis. Estimates which contained data by province are summarized in Table 10-2.

None of the Submittors addressed the impact of the NEP on total booked reserves but some companies provided evidence of the expected effects of the NEP on specific pools, fields or areas. The concerns generally concentrated on premature abandonment of producing wells and the effect the NEP would

Table 10-1

SUMMARY OF MAJOR ASSUMPTIONS FOR OIL SUPPLY FORECASTS

Supply Category		Assumptions For Base Case	Changes in Assumptions From Base Case For: Modified Base Case	Low Case	High Case
Established Reserves		—booked reserves; light 662 x 10^6m^3 heavy 128 x 10^6m^3 —NEP prices starting at $115/$m^3$ in 1981 —current fiscal conditions	—modify fiscal systems or price to optimize production from booked reserves	—none	—modify fiscal systems or price to optimize production from booked reserves
Reserves Additions	Discoveries	—undiscovered potential; light 225 x 10^6m^3 heavy 80 x 10^6m^3 —90 percent of potential added in forecast period	—none	—undiscovered potential; light 125 x 10^6m^3 heavy 40 x 10^6m^3	—undiscovered potential; light 400 x 10^6m^3 heavy 125 x 10^6m^3
	Enhanced Recovery	—technical potential; light 527 x 10^6m^3 heavy 668 x 10^6m^3 —NEP price $189/$m^3$ —choice of recovery factor or incremental production method —no tax on LPG fluids	—increase price to $239/$m^3$ for light crude oil. Reduce royalties on heavy oil in Saskatchewan	—incremental production definition only —recovery reduced 25% for technical risk	—increase price to $300/$m^3$ for light oil and $230/$m^3$ for heavy crude oil
Oil Sands		—NEP price $239/$m^3$ —current royalties and taxes	—increase price to between $260 and $300/$m^3$ —reduce royalties and/or taxes	—none	—as in modified base case
Pentanes Plus		—based on production forecasts for associated and non-associated gas	—none	—none	—none
Frontier		—booked reserves 50 x 10^6m^3 at Hibernia	—add 50 x 10^6m^3 reserves additions at Hibernia	—no frontier production	—add 100 x 10^6m^3 reserves additions at Hibernia —add 150 x 10^6m^3 reserves additions in Beaufort Sea

Table 10-2

ESTABLISHED REMAINING RECOVERABLE RESERVES OF LIGHT AND HEAVY CRUDE OIL AS OF 31 DECEMBER 1979
Comparison of Estimates
(Millions of Cubic Metres)

	CPA	Provinces	Ontario	Dome	Imperial	Petro-Canada	NEB(3)	NEB(5)
Territories	21.0	19.1(1)	10.6	6.0	39.0	19.1(1)	5.7	5.5
British Columbia	28.0	28.5	28.5	28.5	29.0	28.5	29.7	27.5
Alberta	908.0	760.0	788.8	760.6	779.0	754.2	671.3	616.6
Saskatchewan	117.0	105.3	196.1	105.2	185.0	109.2	93.3	89.0
Manitoba	6.0	6.3(1)	6.3	7.2	6.0	5.9	6.7	6.1
Ontario	1.0	1.0(1)	1.5(2)	1.0	1.0	1.0(1)	0.8	0.7
Canada(4)	1 081.0	920.2	1 031.8	908.5	1 039.0	917.9	807.5	745.4

(1) Average of other Submittors.
(2) Includes Ontario and New Brunswick.
(3) NEB estimate does not include reserves from future enhanced recovery schemes and in particular for Norman Wells.
(4) Estimates do not include established reserves from frontier areas.
(5) NEB preliminary estimate as of 31 December 1980.

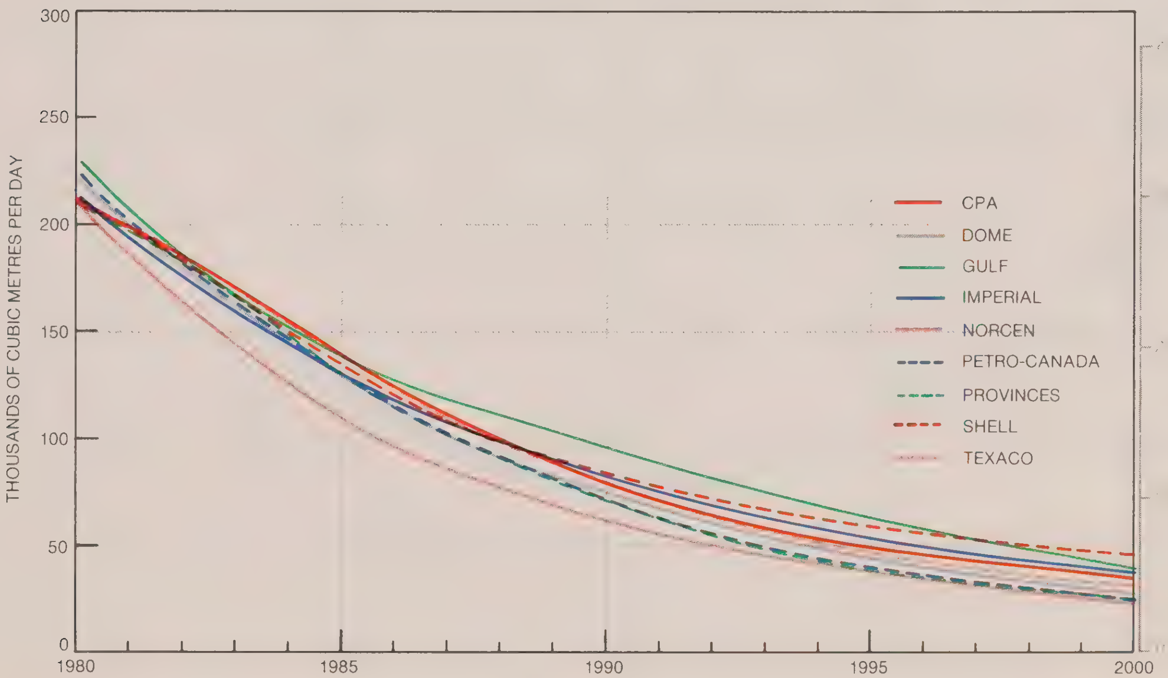

Figure 10-1 Productive Capacity from Total Established Reserves of Crude Oil
Comparison of Forecasts: Pre-NEP

have on the drilling of infill wells required to recover the booked reserves.

Productive capacity forecasts were submitted on individual pools and on a composite basis. Composite forecasts are shown on Figure 10-1. Norcen provided the lowest forecast throughout the forecast period, whereas CPA, Gulf and Shell showed the highest level of supply at differing times in the forecast period. The differences among forecasts reached a maximum of 30 thousand cubic metres a day in the late 1980s.

Only four Submittors revised their forecast to illustrate the expected impact of the NEP on productive capacity. On average these forecasts showed a reduction in supply compared with the pre-NEP forecasts and this reduction increased from about 12.5 thousand to 26.5 thousand cubic metres per day in the period 1981 to 1985 and decreased thereafter. The revised forecasts are shown in Figure 10-2. However, Submittors stressed that the revised forecasts were of an illustrative nature as it was too early to properly assess the full impact of the NEP. Most Submittors attributed the reduction in supply to the following four factors:

1. Oil wells in Saskatchewan that were unable to carry the additional cost of the PGRT would be shut in or produced at reduced rates to minimize losses. Murphy stated that about 25 percent of its wells in Saskatchewan would have to be shut down resulting in an immediate ten percent loss of production. Other companies referred to the fact that many heavy oil pools in Saskatchewan had shown a marked decrease in production in the beginning of 1981 in an apparent attempt to minimize losses in revenue.
2. Booked reserves would be uneconomic to drill owing to the abolition of the depletion allowances for infill wells and the imposition of the PGRT. For example, Chevron provided revised pool production forecasts for the Mitsue Gilwood "A" and Kaybob Beaverhill Lake A pools which showed reduced productive capacity that reached 520 cubic metres per day. The associated reduction in reserves amounted to 3.2 million cubic metres.
3. Increased production of gas and water along with the oil would require the installation of new lifting equipment and processing facilities which could not be economically justified with rising operating costs, NEP prices and taxes, and declin-

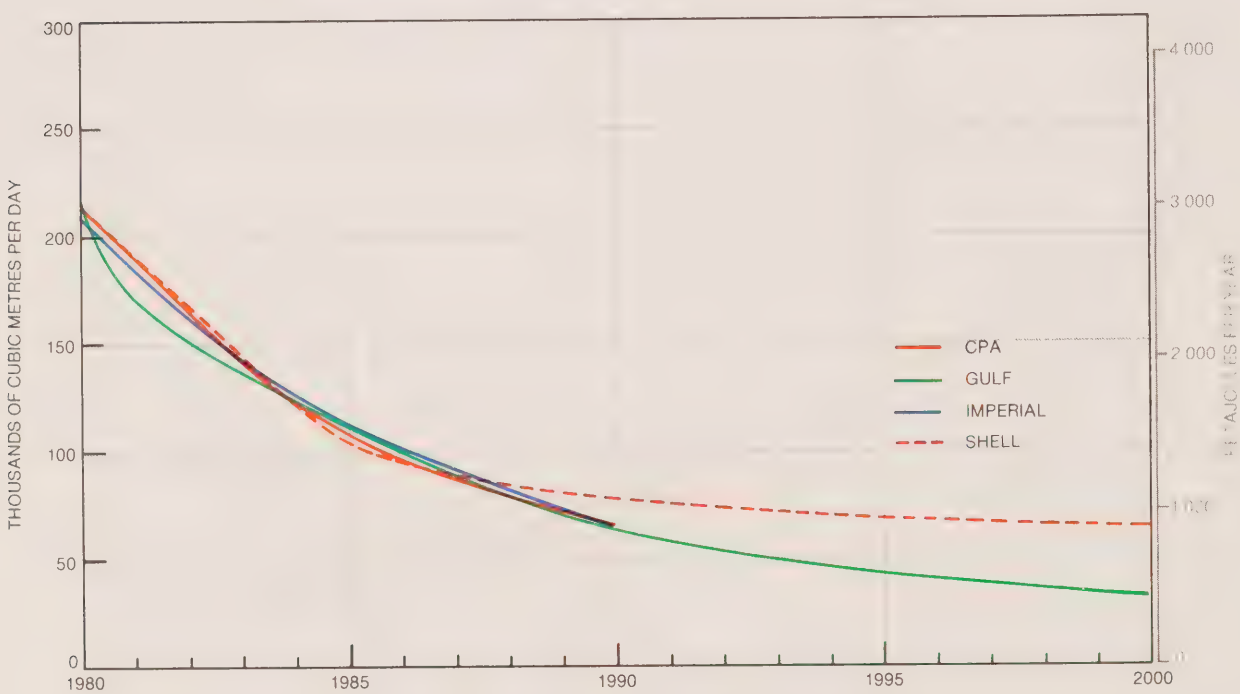

Figure 10-2 Productive Capacity from Total Established Reserves of Crude Oil
Comparison of Forecasts: Post-NEP

ing oil production. CPA provided projections of operating costs showing that average netbacks after deducting operating costs would become negative by 1984. According to CPA this indicated that production operations would have to be substantially altered to minimize operating costs, which would lead to a reduction in productive capacity.

4. Marginal wells would be prematurely abandoned. Imperial provided an economic analysis which showed that two of its major pools would become uneconomic by 1985. Shell made similar claims for two of its pools.

Operating costs received much attention during the inquiry and Submittors generally supported CPA's views that operating costs would increase rapidly owing to increasing volumes of water produced with the oil. Increasing complexity of operations and the consequential increase in engineering demands were also sited as significant factors. It was emphasized that the effect of these cost increases would be aggravated by declining oil production when such costs were calculated as a cost per barrel of produced oil.

CPA estimated that average water production had increased by 23.5 percent per year from 1970 to 1979 and that average per well operating costs had increased by 21 percent per year or about 10 percent per year in real terms. CPA projected that operating costs per well would continue to increase by ten percent per year in real terms. A future operating cost per barrel was then calculated from projected average oil production per operating well. From this study CPA concluded that operating costs would increase in real terms from $14.50 per cubic metre in 1980 to about $37 per cubic metre in 1985. A ten percent average inflation rate would escalate these costs to $60 per cubic metre in 1985. Imperial provided similar projections of operating costs.

Gulf quoted annual increases in operating costs that varied from 12 percent in 1980 to 31 percent in 1979. Gulf attributed these cost increases to increases in fixed costs for each producing well and increases in variable costs associated with the amount of total fluid being produced. Gulf submitted that cost increases were expected to continue as experienced in 1979 and 1980.

Mobil supported CPA's estimates but emphasized that these estimates were average costs and did not reflect costs in specific fields. To illustrate this point Mobil quoted operating costs for various fields and areas showing that heavy oil experienced higher operating costs.

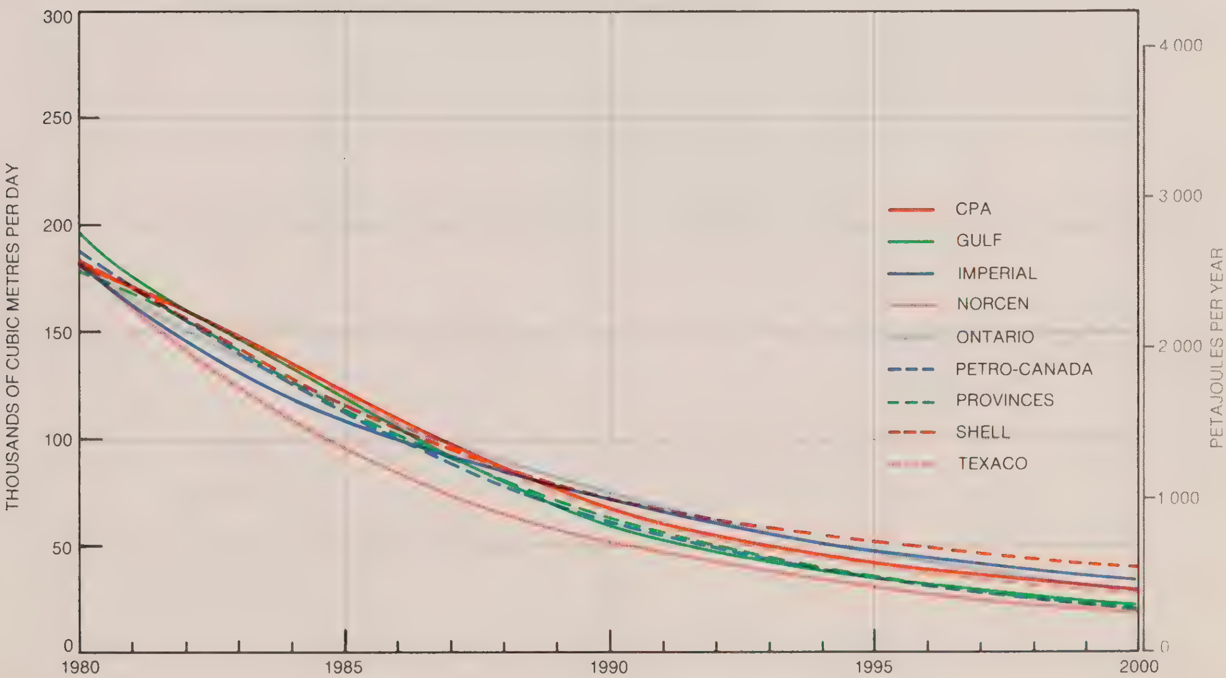

Figure 10-3 Productive Capacity from Established Reserves of Light Crude Oil Comparison of Forecasts: Pre-NEP

Murphy submitted that operating costs for heavy crude oil were about double the cost for light crude oil.

Some Submittors provided separate productive capacity forecasts for light crude oil and heavy crude oil. Light crude oil forecasts are compared graphically in Figure 10-3. Norcen provided the lowest forecast, whereas Gulf, Texaco, Dome and Shell showed the highest level of supply at successive time periods. The differences among forecasts reached a maximum of 25 thousand cubic metres per day in about 1985. Of the Submittors who provided separate forecasts for light and heavy crude, only Gulf and Imperial revised their forecast to illustrate the expected impact of the NEP on productive capacity. These revised forecasts, which are shown on Figure 10-4, indicated a reduction in supply that increased from 18 to 20 thousand cubic metres per day in the period 1981 to 1985. After 1985 the reduction became gradually less significant.

With regard to light crude oil supply, some of the Submittors also provided information on the effect of the Alberta production cutbacks on their operation. This evidence indicated that these cutbacks, which affect pools that are located totally on Crown lands, could reduce production in high productivity pools by just over 50 percent if the cutbacks were fully implemented. Submittors foresaw no major problems with such cutbacks except in fields where solution gas produced with the crude oil was a major part of the gas stream into a gas processing plant. In such cases, plants might have to be shut down temporarily if insufficient solution gas were available.

Heavy crude oil forecasts are compared graphically in Figure 10-5. Norcen provided the lowest forecast whereas Petro-Canada, Imperial and Shell showed the highest level of supply at successive time periods. The spread between the low and the high forecasts gradually diminished from 6000 cubic metres per day in 1981 to 2400 cubic metres per day in the year 2000. Only Gulf and Imperial provided revised forecasts. These forecasts, which are shown in Figure 10-6, indicated only a very marginal effect of the NEP on heavy crude oil supply from established reserves. However, Husky stated that of the 2000 wells in the Lloydminster area, 500 wells could not support direct operating costs and would not be continued in operation unless the current financial circumstances were to change. A further 800 wells would not support maintenance costs as they become necessary over the next 18 months. Similar opinions were voiced by other Submittors who had significant interests in heavy oil production in Saskatchewan.

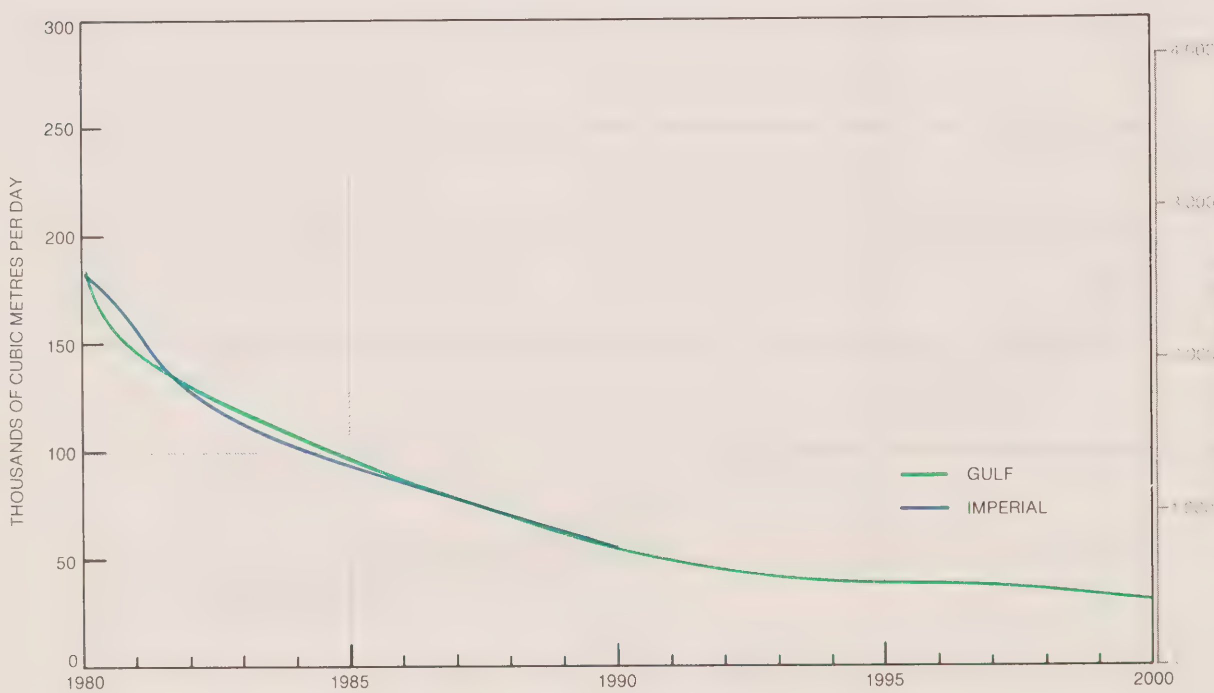

Figure 10-4 Productive Capacity from Established Reserves of Light Crude Oil Comparison of Forecasts: Post-NEP

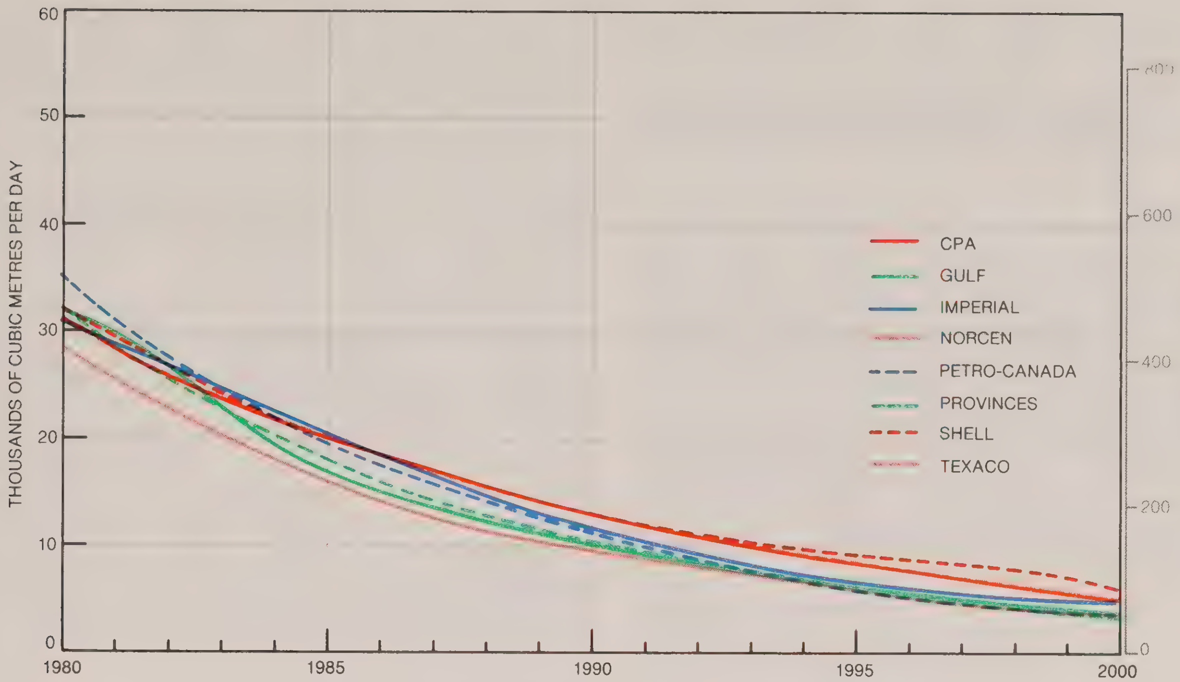

Figure 10-5 Productive Capacity from Established Reserves of Heavy Crude Oil
Comparison of Forecasts: Pre-NEP

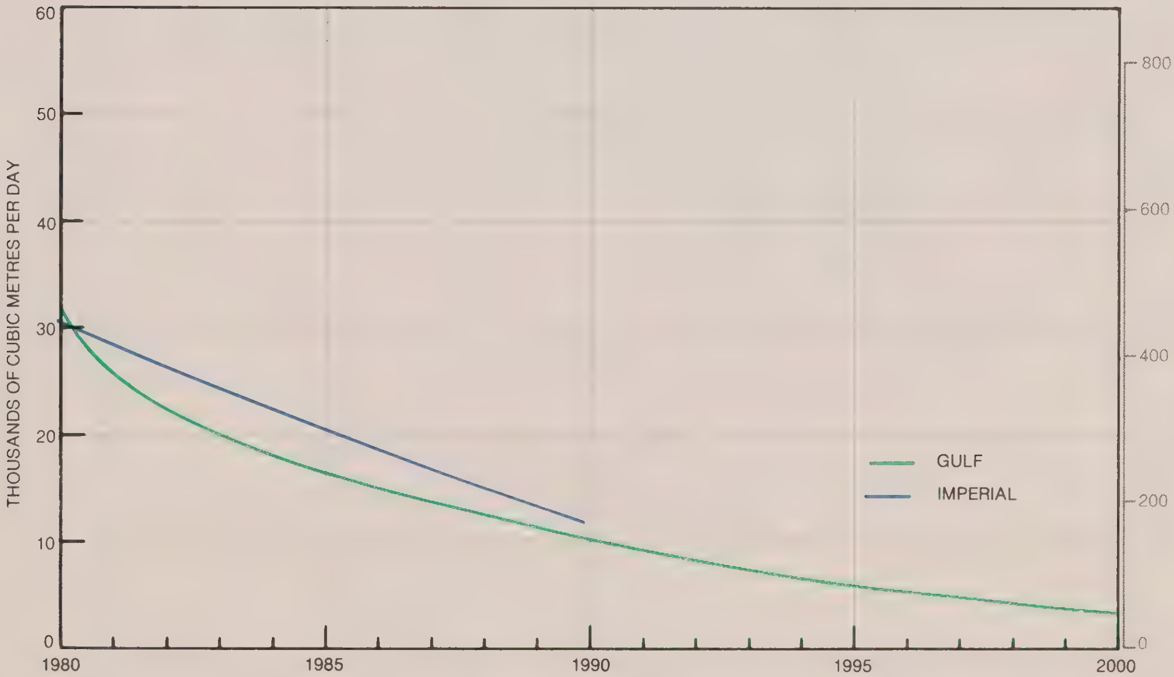

Figure 10-6 Productive Capacity from Established
Reserves of Heavy Crude Oil
Comparison of Forecasts: Post-NEP

Mobil stated that the combined effect of the NEP and provincial royalties would place Mobil's operations in Saskatchewan in a "cash loss" position. Mobil further stated that a severe decline in the productive capacity of Saskatchewan fields was certain unless immediate remedial steps were taken to restore profitability.

Views of the Board

In making its estimates of established reserves, the Board has taken into account all the relevant evidence received at the inquiry and the results of its own studies. The Board's estimates for reserves in the conventional areas shown in Table 10-2 are based on an analysis of 212 reservoirs encompassing 87 percent of the reserves. These estimates and estimates for the remaining reserves are summarized in tabular form in Appendix K. The estimates are arranged by pipeline system, province and territory showing totals for each of these areas in addition to the Canadian totals. These estimates of established reserves were not changed from case to case.

In the previous oil reports, the Board did not find that economic conditions would limit productive capacity from established reserves prior to well abandonment. In the present circumstances, however, for the base case, the Board concludes that productive capacity for many pools will be reduced from levels forecast by the Board in its previous oil reports. The reasons for this relate mainly to economic viability rather than altered geological or technological limitations.

For its modified base case the Board assumes that producer netback will be such that it will permit continued optimizing of production from all established reserves. This forecast is shown on a pool by pool basis in Appendix K.

Variations in supply from established reserves outside of the range defined by the base case and modified base case are not considered to be likely. Consequently, for this category the Board has assumed the low case to be equal to the base case, and the high case to be equal to the modified base case.

The results of the base case and the modified base case are shown on Figure 10-7. The difference in productive capacity between the two cases is attributable to a combination of the NEP measures and the current provincial royalty and taxation schedules, and this difference could reach a maximum of ten thousand cubic metres per day, in 1983. The major reasons for these differences are discussed later in this chapter in the sections on light and heavy crude supply.

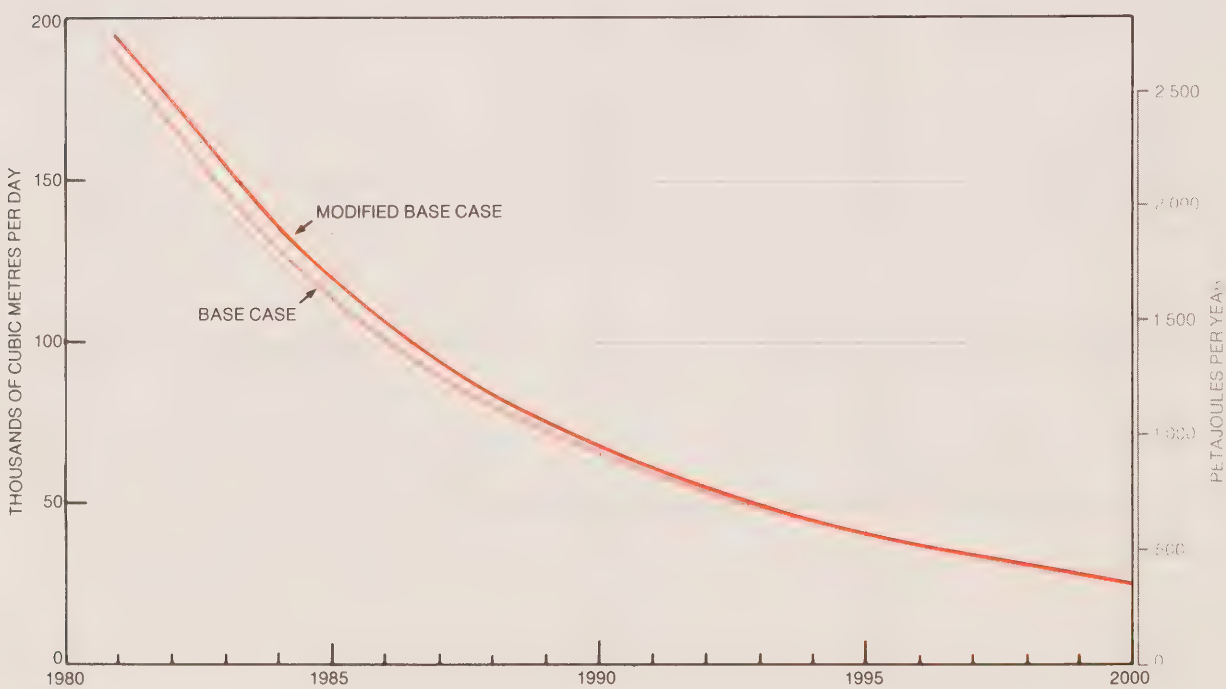

Figure 10-7 Productive Capacity from Total Established Reserves of Crude Oil
NEB Forecast
(as of December 31, 1979)

The Board has given consideration to the evidence on operating costs and recognizes that real operating costs per cubic metre of oil produced will continue to escalate because of declining well productivity and increasing water-oil ratios.

The Board has prepared its own estimates of operating cost increases for 1985 and these are compared to NEP and CPA estimates in Table 10-3.

Table 10-3

COMPARISON OF ESTIMATES OF 1985 OPERATING COSTS
($/m³)

	Constant 1980	1985
NEP	—	18.88
CPA	37.84	60.69
NEB	23.95	39.28

The method used by the Board to calculate operating costs is discussed in Appendix L.

Because of the different market situations, the Board has again prepared separate forecasts for light and heavy crude oil. The Board's definition of heavy crude oil is included as Appendix J.

The Board's forecasts of productive capacity of light crude oil are shown in Figure 10-8. The base case productive capacity forecast initially declines faster than the modified base case and reaches a maximum difference of nearly five thousand cubic metres per day in 1983. This reflects a reduction in infill drilling, which is mainly attributable to the abolition of the depletion allowance for infill drilling and the introduction of the PGRT. The diminishing profitability of producing operations is expected to result in a reduced investment level in lifting equipment and early abandonment of marginal wells. Although the more rapid crude price escalation after 1983 proposed under the NEP is expected to reduce early abandonments, there is concern with the level of producer netback on deep, high cost wells which appear to become unprofitable, even at relatively high production rates. Wells in the Beaverhill Lake reservoirs are a case in point.

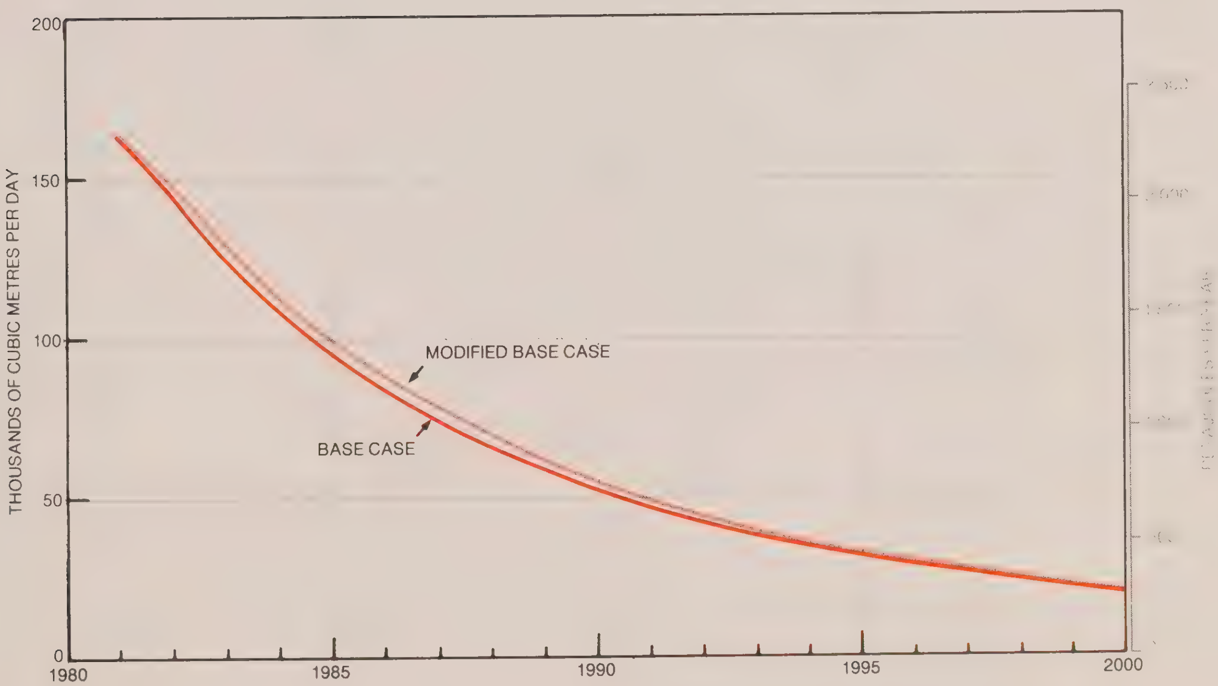

Figure 10-8 Productive Capacity from Established Reserves of Light Crude Oil
NEB Forecast
(as of December 31, 1979)

These forecasts do not include the effect of Alberta's stated intention to conditionally withhold 28.6 thousand cubic metres per day (180 thousand barrels per day) of light crude oil supply in the absence of an energy pricing agreement. If such a reduction were to continue, productive capacity would be reduced by some 20.1 thousand cubic metres per day in 1985, and 13.7 thousand cubic metres per day in 1995. As time progresses the effect would diminish because supplies that are shut-in earlier would add to the supply in the later years.

The Board's forecasts of heavy crude oil productive capacity are shown in Figure 10-9. The base case forecast declines sharply in the early years of the forecast, owing to sharply reduced profitability in Saskatchewan. Based on considerable evidence regarding the lack of profitability of Saskatchewan operations, the Board concludes that the average netback received by producers in this province is too low to sustain the costs of maintaining all wells and production equipment in good operating condition. This is especially true in the heavy oil areas of Western Saskatchewan. Consequently the base case production forecast assumes that all unprofitable operations would be shut-down and that some wells would produce below peak capacity to optimize profits under the existing fiscal and royalty regime. The Board is aware that such a forecast shows the lower limit of productive capacity and that production may initially not fall to forecast levels as producers may be able to temporarily reduce operating costs by deferring expenditures. Nevertheless, the indicated lack of profitability in Saskatchewan will eventually lead to a significant reduction in supply of heavy crude oil and could also result in some loss of reserves through premature abandonment of marginal producing wells.

10.2.2 *Reserves Additions, Ultimate Potential and Productive Capacity*

Views of Submittors

Light Crude Oil

As in the case of the 1978 oil hearing, the reserves additions estimates submitted by most companies were fairly evenly balanced between additions from new discoveries and additions from enhanced recovery projects. Most companies agreed that little additional supply could be expected from appreciation of established reserves. The estimates of reserves additions sub-

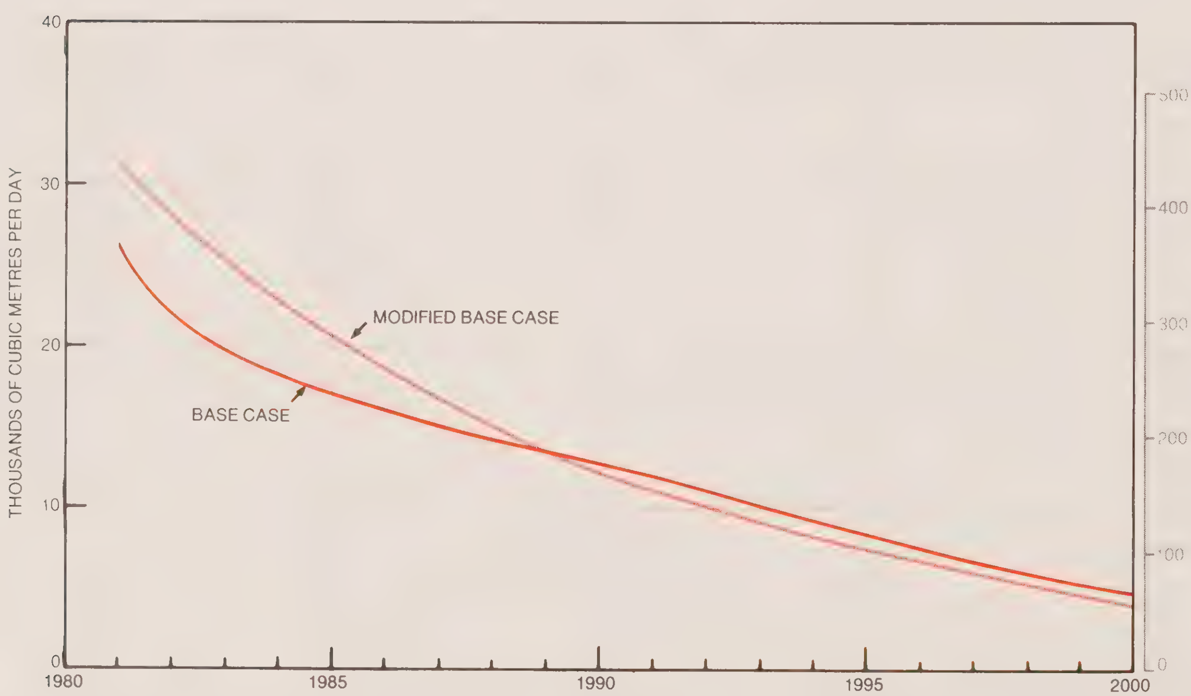

Figure 10-9 Productive Capacity from Established Reserves of Heavy Crude Oil NEB Forecast (as of December 31, 1979)

mitted prior to the NEP, as well as IPAC's enhanced recovery ultimate potential, are summarized in Table 10-4. Caution must be exercised in comparing individual components because Submittors used differing terminology and a wide range of assumptions for exploration activity, crude oil price and producer netback.

Some Submittors stressed the importance of higher netbacks for finding and developing new oil pools. Dome projected total productive capacity of new discoveries under a moderate netback case and an incentive netback case. The moderate case assumed producer netbacks of $44 per cubic metre increasing to $145 in the year 2000, whereas the incentive case assumed $125 per cubic metre increasing to $283 in the year 2000. Dome showed that productive capacity from new discoveries would increase rapidly under the incentive case and would be about 250 percent of the forecast productive capacity under the moderate case by the year 2000.

Figures 10-10, 10-11, and 10-12 summarize Submittors' pre-NEP forecasts of productive capacity from additions to reserves of light crude oil. Although Submittors differed as to the level of productive capacity from appreciation and new discoveries, they were in general agreement that it would peak or level out in the early to mid-1990s. As a result of the long lead times required, supply from enhanced recovery reserves was not expected to reach significant levels until the late 1980s. Submittors felt it would then continue to increase through to the end of the forecast period.

As a result of the opportunity provided by the Board to submit forecasts based on the NEP, Submittors provided evidence on the economics of supply with emphasis on the fiscal measures which affected the supply of crude oil from reserves additions.

Submittors generally agreed that the rate of discovery and development of new reserves would depend on the expected profitability in Canada, as compared to the other areas of the world, especially the United States. The cash flow available to the industry would also affect reserves additions since exploration expenditures traditionally have been financed almost entirely by internally generated funds.

Some Submittors indicated that the return to the company on new oil was five to six times higher in the United States than in Canada. However, Petro-Canada believed the appropriate comparison was not the current return to the company but the overall project economics. Better geological prospects in Canada, evidence of higher land costs in the United States, and provisions in the NEP would tend to make the full-cycle present value of investments in Canada and the United States approximately equal.

Although most Submittors did not provide detailed post-NEP forecasts of reserves additions, directional estimates were provided. The general consensus was that the reserves additions resulting from exploration in Western Canada would be reduced by 20-50 percent from the pre-NEP forecast levels. A notable exception to this opinion was Petro-Canada, which foresaw no change in reserves additions from new discoveries.

Table 10-4

RESERVES ADDITIONS OF LIGHT CRUDE OIL
1980-2000
Comparison of Estimates
Pre-NEP
(10^6m^3)

	Appreciation	New Discoveries	Enhanced Recovery	Total
Gulf	83.6	385.5	193.1 (2)	662.2
Imperial	0	444 (3)	315	759
NOVA	—	—	280-340	—
Ontario	—	148.0 (1)	148.8	296.8
Petro-Canada	—	—	—	369.7
Shell	36.5 (2)	253	—	—
CPA	18	213 (3)	365	596
IPAC: Performance Risk case ultimate potential				
$50/m³ Netback	—	—	0	—
$75	—	—	45	—
$100	—	—	70	—
$150	—	—	214	—
Technical Limit	—	—	520	—
Provinces				
British Columbia	.3	27.8	16.0	44.1
Saskatchewan	7.9	10.7	14.3	32.9

(1) Includes appreciation of established reserves
(2) Includes heavy crude oil
(3) Includes enhanced recovery from forecast new discoveries

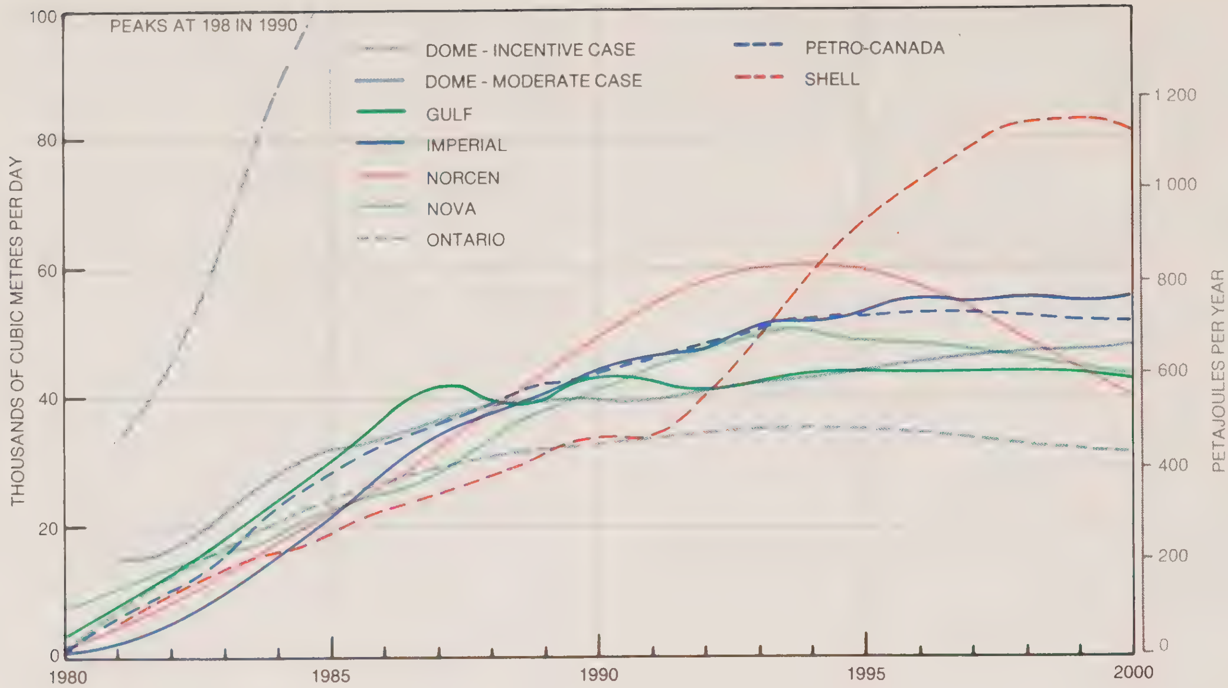

Figure 10-10 Productive Capacity from Reserves Additions of Light Crude Oil Comparison of Forecasts: Pre-NEP

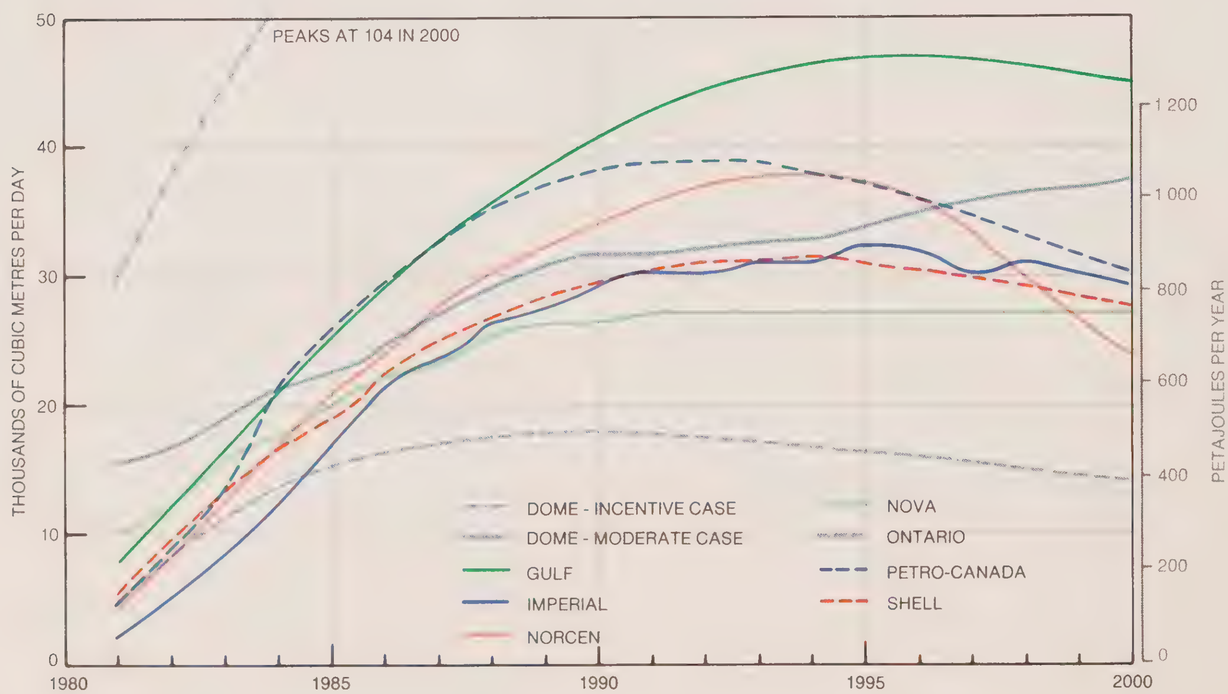

Figure 10-11 Productive Capacity from Appreciation and New Discoveries of Light Crude Oil Comparison of Forecasts: Pre-NEP

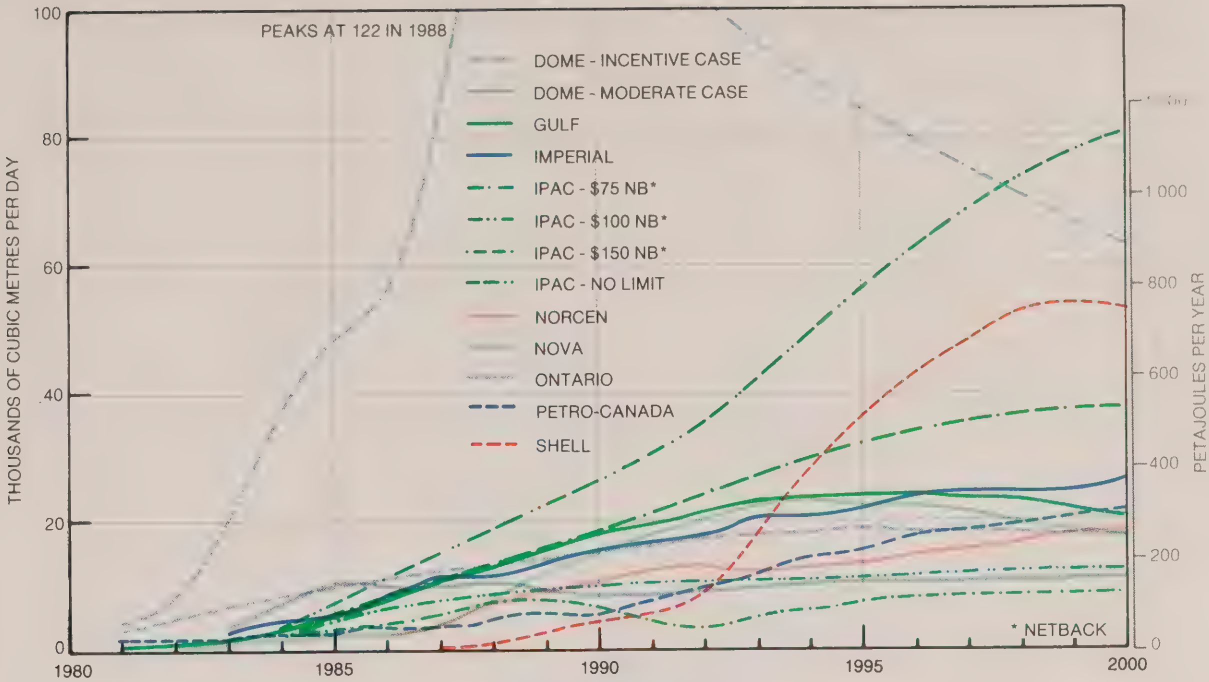

Figure 10-12 Productive Capacity from Enhanced Recovery of Light Crude Oil Comparison of Forecasts: Pre-NEP

Most Submittors felt that the tertiary incentive price offered by the NEP was a move in the right direction, but foresaw little production increase from light crude oil tertiary projects because of the tax and royalty regimes, high project costs, and other uncertainties.

Most Submittors observed that the PGRT would offset some of the price supplement contained in the NEP and that the price was limited to increases based on the CPI. Submittors also noted that the NEP tertiary price was conditional on provincial incentive programs remaining in place. There was also uncertainty as to how tertiary oil would be defined in order to qualify for the incentive price.

The cost of hydrocarbons and carbon dioxide was cited as a critical factor since these injection materials represented the majority of costs for light crude oil miscible projects. Submittors indicated that the cost of hydrocarbons (ethane, propane, and butanes) was related to the cost of oil and would likely rise faster than the CPI. Similarly, the cost of carbon dioxide was expected to rise rapidly if increased demand required the development of more costly sources. Several Submittors indicated that the current cost of carbon dioxide was in the range of 7 to 12 cents per cubic metre. Imperial estimated a cost of 12 cents per cubic metre in 1983 for carbon dioxide for its proposed Judy Creek project. IPAC's analysis of tertiary potential indicated that a change in carbon dioxide cost from 7 to 11 cents per cubic metre would reduce tertiary light crude oil recoverable reserves by approximately one-half at current netback levels. IPAC defined netback to be revenue less payments to goverments.

Submittors noted that the optimum quantity of injection materials was uncertain and subject to change as operating experience was gained with each project. The estimated volume of oil that would be recovered was also uncertain and subject to considerable risk. IPAC found that at current level of producer netback, a 25 percent reduction in expected oil recovery would reduce project economics so that only one-third of the previously calculated reserves potential would be recovered. Imperial reduced its estimate of tertiary recovery from the Judy Creek and similar pools by 30 percent as a result of recent pool performance. This revision accounted for approximately one-half of the reduction in tertiary potential shown in Imperial's post-NEP estimates.

Figures 10-13 and 10-14 illustrate the relationship of recoverable reserves to producer netback and price as submitted by

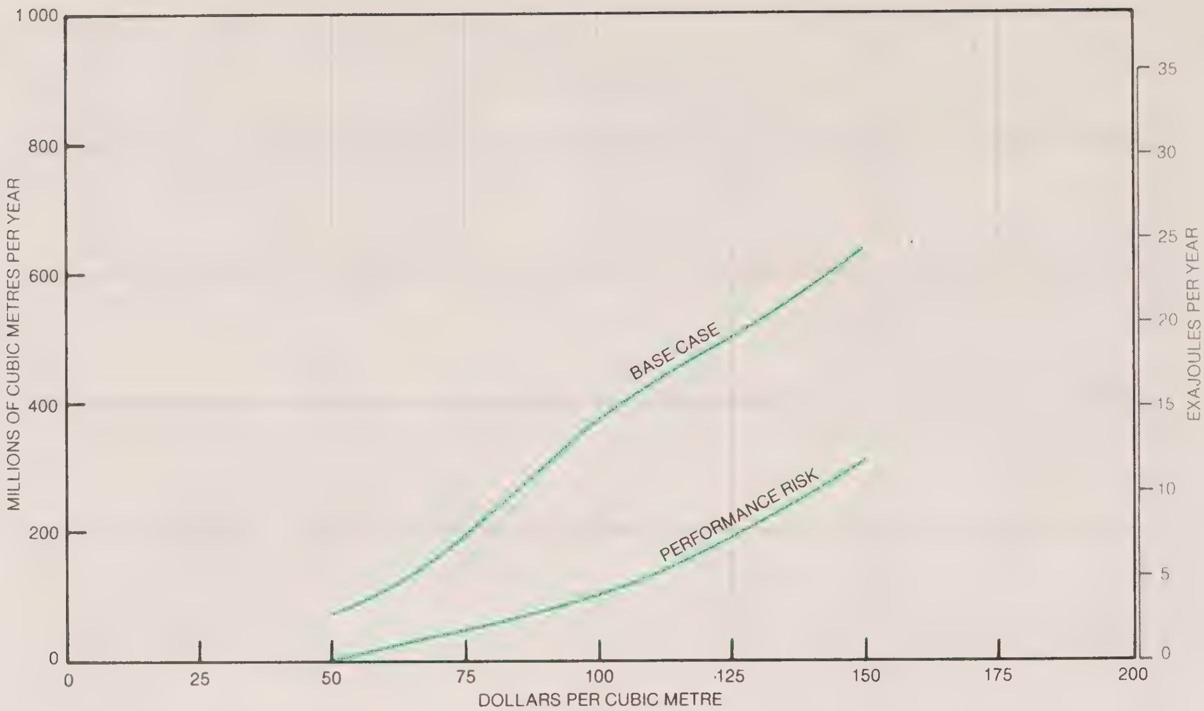

Figure 10-13 Enhanced Oil Recovery: IPAC Forecast
Producer Netback vs. Recoverable Reserves

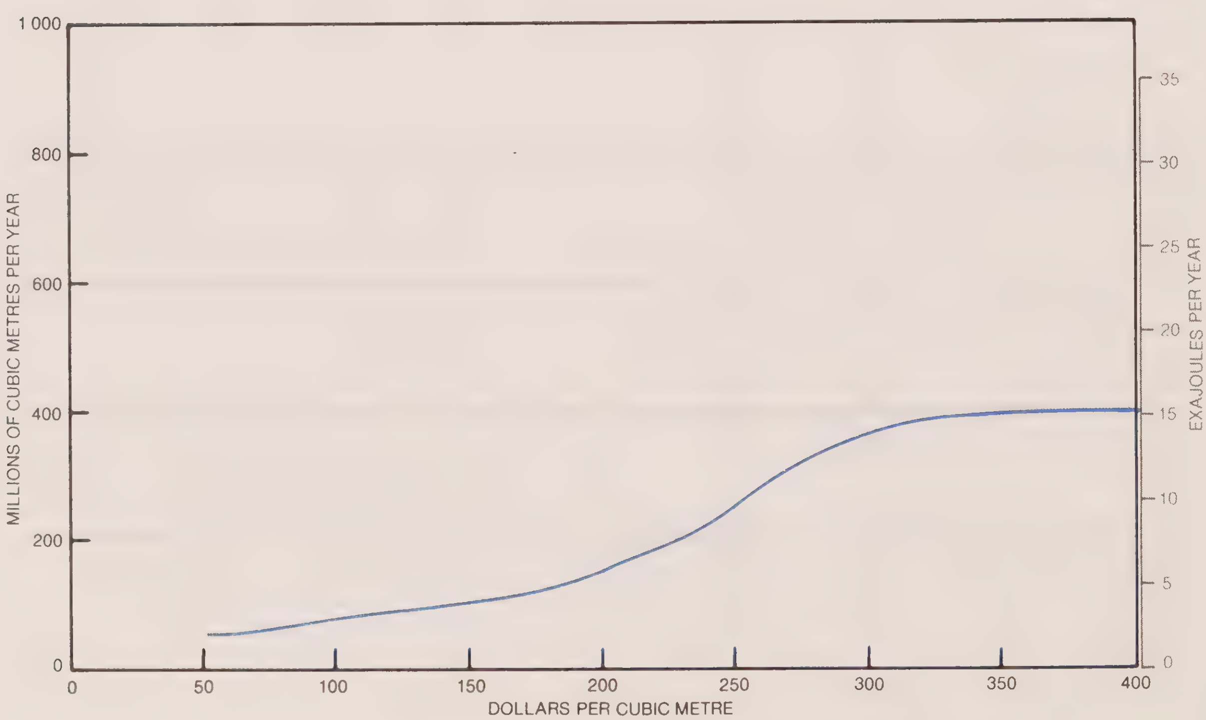

Figure 10-14 Enhanced Oil Recovery: Imperial Forecast
Crude Oil Price vs. Recoverable Reserves

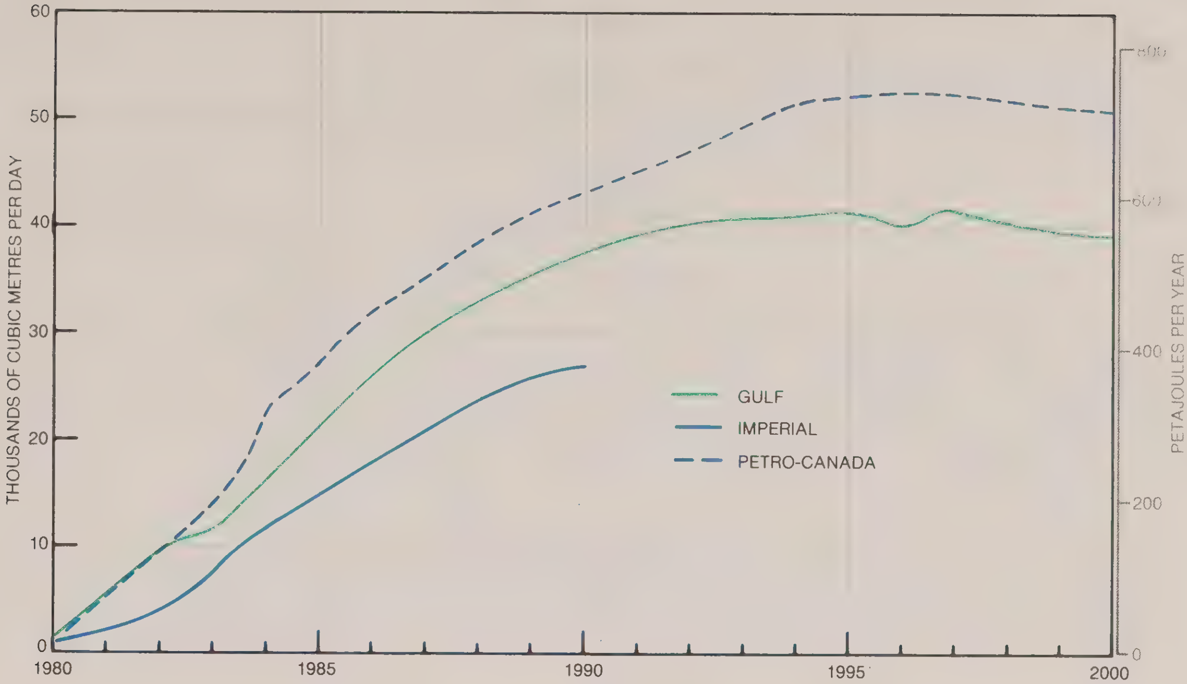

Figure 10-15 Productive Capacity from Reserves Additions of Light Crude Oil Comparison of Forecasts: Post-NEP

IPAC and Imperial respectively for both light and heavy crude oil tertiary recovery. IPAC estimated the post-NEP netback to be $85 per cubic metre. IPAC's Performance Risk Case assumed a 25 percent reduction in oil recovery and was felt to be the more probable scenario.

Figure 10-15 summarizes the post-NEP forecast of productive capacity from light crude oil reserves additions.

Heavy Crude Oil

Table 10-5 summarizes Pre-NEP estimates of reserves additions and ultimate potential of heavy crude oil. Some Submittors were of the opinion that the location of most, if not all, heavy crude oil was already known and was only awaiting economic conditions which would allow conventional development or enhanced recovery to proceed. Other Submittors presented forecasts more balanced between new discoveries and enhanced recovery although much of the reserves attributed to new discoveries were expected to be recoverable only through the use of tertiary recovery techniques. Overall, it was felt that the heavy crude oil potential of Western Canada would be developed mainly through the use of tertiary recovery techniques such as steam stimulation, steam floods and fire floods.

It was felt that the Lloydminster area had the greatest potential for additions to heavy crude oil reserves and therefore that area drew special attention from some submittors. Table 10-6 summarizes the estimates of oil-in-place for the Lloydminster area.

Very little of this oil was expected to be recovered by conventional means. The Submittors were in agreement that extensive use of tertiary recovery techniques would be required to develop the heavy oil resource of the Lloydminster area. Husky indicated that only five percent of the Lloydminster oil in place was found in deposits thick enough to use steam stimulation or steam flooding. The remaining thin deposits might lend themselves to fire flooding techniques although Husky noted that the two fire flood tests conducted in the Lloydminster area yielded no definite results.

Figures 10-16, 10-17 and 10-18 summarize the productive capacity forecasts of reserves additions from heavy crude oil. By the year 2000 the estimates of productive capacity from additions to reserves of heavy crude oil ranged from less than 10 000 cubic metres per day to more than 80 000 cubic metres per day.

Table 10-5

RESERVES ADDITIONS OF HEAVY CRUDE OIL 1980-2000 Comparison of Estimates Pre-NEP

(millions of cubic metres)

	Appreciation	New Discoveries[1]	Enhanced Recovery	Total
Gulf	22.4	291.6	193.1[2]	507.1
Husky—Lloydminster Area (Ultimate)	—	18	330	348
Imperial	—	77 [3]	109	186
NOVA-Lloydminster Area (Ultimate)	—	—	490	—
Ontario	—	—	—	165.5[4]
Petro-Canada	—	—	—	216.3
Shell-Lloydminster Area	—	165	—	—
—Lloydminster Area (Ultimate)	—	310	—	—
—Other	—	30	—	—
CPA	181 [1]	36	265	482
IPAC: Performance Risk case Ultimate Potential				
$50/m³ Netback	—	—	0	—
$75	—	—	1.2	—
$100	—	—	27.4	—
$150	—	—	91.4	—
Technical Limit	—	—	215.8	—
Provinces				
Saskatchewan	30.9	39.2	105.7	175.8

[1] Includes enhanced recovery from new reserves
[2] Includes light crude oil
[3] Undeveloped reserves
[4] Includes 110 million cubic metres from the Lloydminster area, all from enhanced recovery.

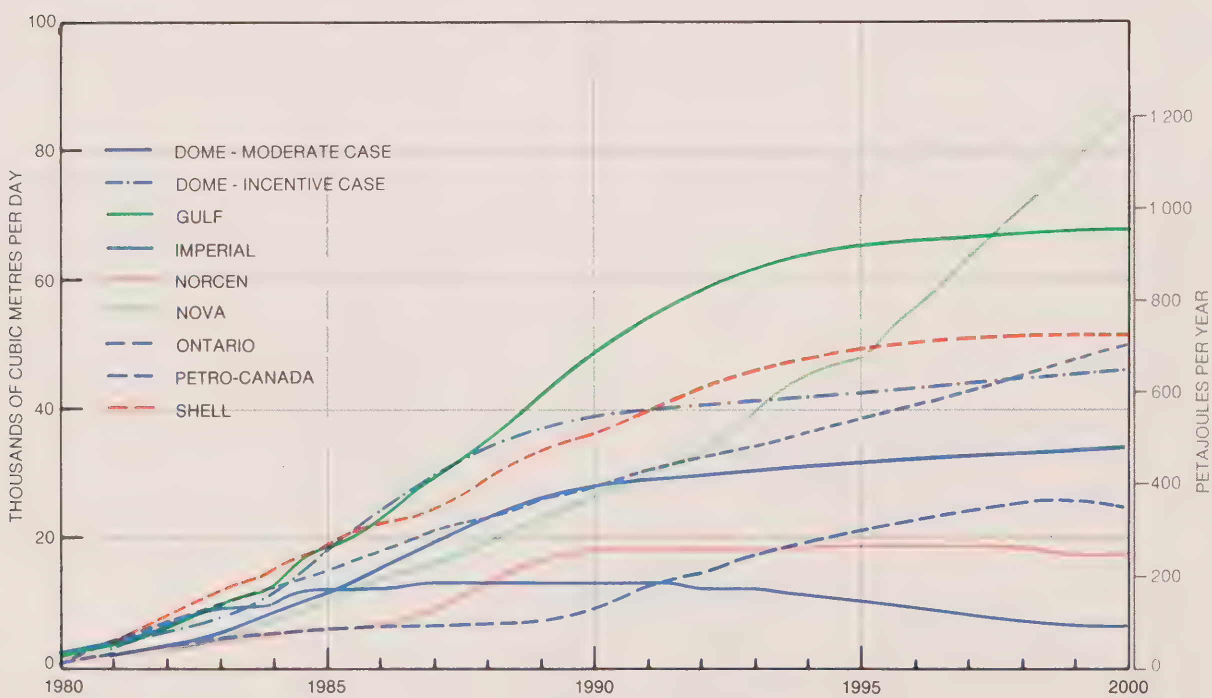

Figure 10-16 Productive Capacity from Reserves Additions of Heavy Crude Oil Comparison of Forecasts: Pre-NEP

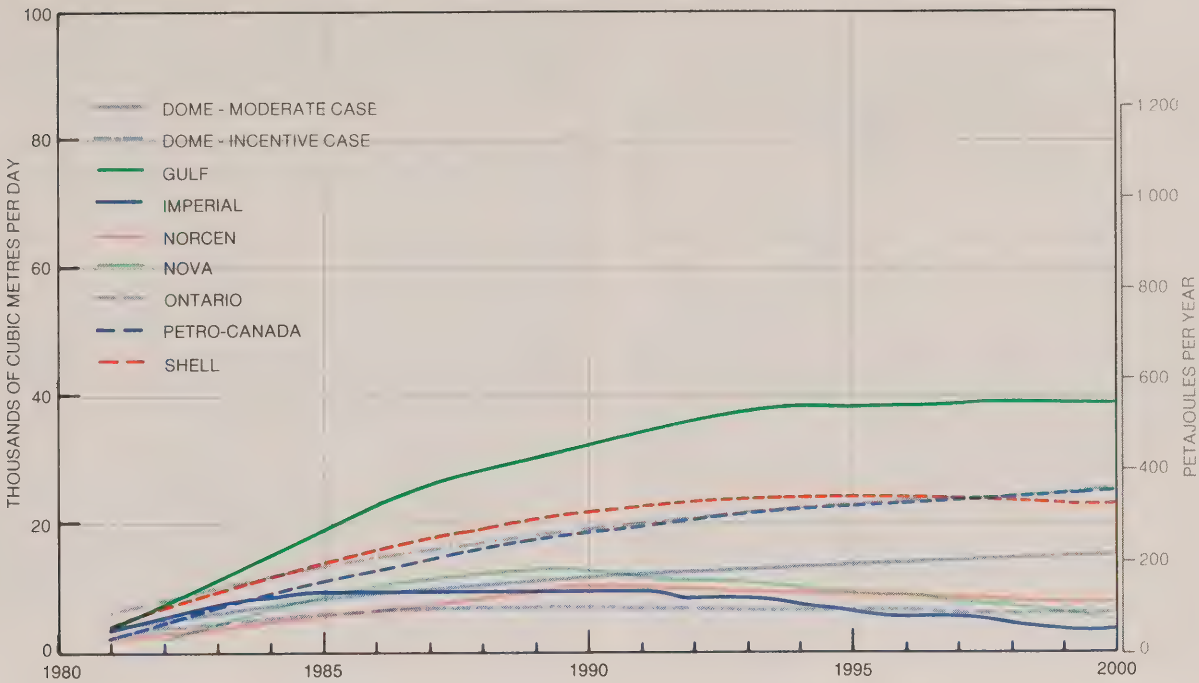

Figure 10-17 Productive Capacity from Appreciation and New Discoveries of Heavy Crude Oil Comparison of Forecasts: Pre-NEP

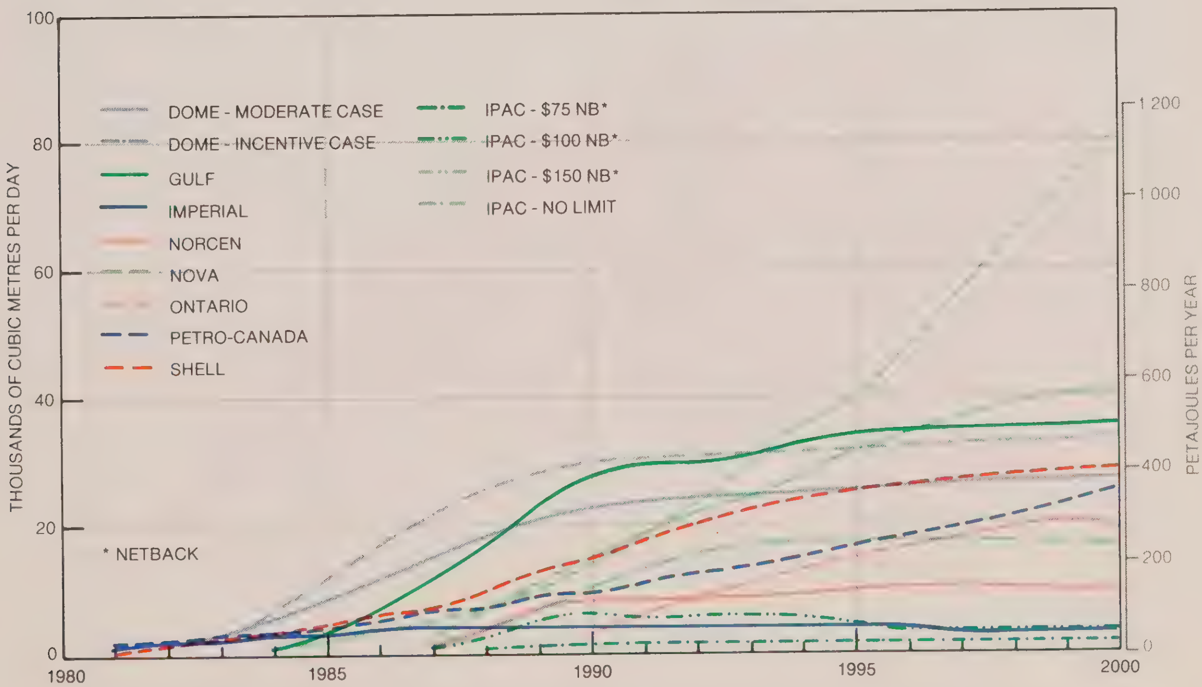

Figure 10-18 Productive Capacity from Enhanced Recovery of Heavy Crude Oil Comparison of Forecasts: Pre-NEP

Table 10-6

ESTIMATED OIL IN PLACE
LLOYDMINSTER AREA HEAVY CRUDE OIL
Comparison of Estimates
(billion cubic metres)

NOVA	6
Husky	8 - 11
Murphy	24
Shell	32.5

Following the NEP, Submittors forecast a 20 to 50 percent decrease in exploration activity. This decrease in activity and the unfavourable economic conditions for heavy crude oil production in Saskatchewan were expected to result in lower heavy crude oil reserves additions from new discoveries. Murphy planned a major reduction in its exploration program in Saskatchewan and intended to reduce its Alberta heavy oil program. Husky indicated that only a few low risk projects and some drilling required to maintain land rights would be continued in Saskatchewan unless economic conditions improved. Shell forecast a 75 percent reduction for heavy oil reserves additions in Saskatchewan by 1983 relative to its pre-NEP forecast.

Most Submittors saw heavy oil tertiary recovery projects in Alberta as marginally economic, while no Submittor expected tertiary heavy oil to be developed in Saskatchewan unless the NEP or existing provincial fiscal regimes were changed.

Figure 10-19 compares those Submittors that quantified post-NEP forecasts of productive capacity from additions to reserves of heavy crude oil.

Views of the Board

Light Crude Oil

The Board's views respecting reserves additions in conventional areas are discussed separately under the two categories which make up reserves additions; discoveries, and enhanced recovery of established reserves.

New Discoveries

In assessing the evidence, the Board recognizes that each Submittors' forecast of productive capacity is based on expectations with regard to crude oil price, producer netback and interpretation of the NEP's expected effects on exploration activity. A substantial element of judgement is involved when estimating future levels of industry activity and undiscovered potential, and estimates can be expected to vary considerably.

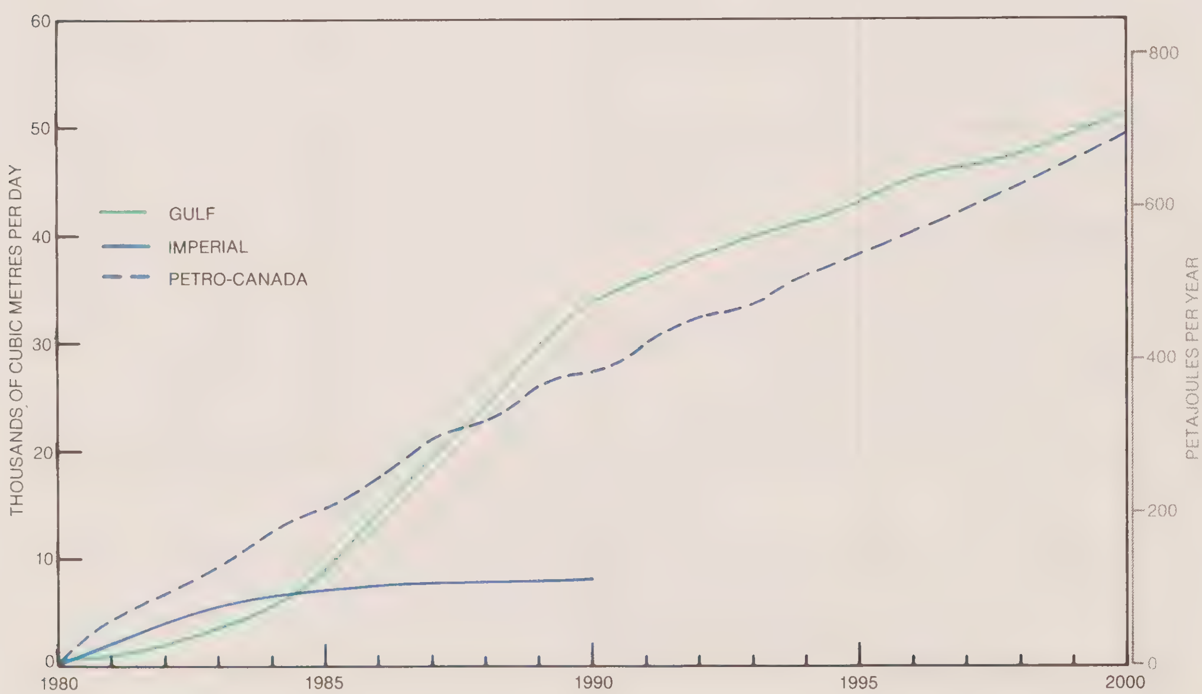

Figure 10-19 Productive Capacity from Reserves Additions of Heavy Crude Oil
Comparison of Forecasts: Post-NEP

The Board's low, base, and high estimates of ultimate potential are unchanged from the 1978 Oil Report, however, discoveries in 1978 and 1979 have been subtracted to arrive at the estimates of year end 1979 undiscovered potential.

The Board's base case and modified base case estimate of remaining undiscovered potential for recoverable light crude oil is 225 million cubic metres. These two cases assume the same geological potential. For the low case the estimate is 125 million cubic metres and for the high case, it is 400 million cubic metres. These estimates of potential include all future reserves additions including EOR for these new discoveries.

The Board believes that lower producer netbacks resulting from the NEP would in turn cause a reduction in annual drilling rates. However, it is felt that oil-directed drilling will not decrease to the same degree as gas-directed drilling, and over the long-term, oil activity is expected to stay near 1980 levels. As a consequence, the Board has adopted the same forecast for the base case and the modified base case. It is assumed that approximately 90 percent of the potential in each of the four cases will be discovered by the year 2000. Figure 10-20 summarizes the productive capacity from new discoveries of light crude oil.

Enhanced Recovery

Based on the evidence and its own studies, the Board has updated its 1976 study on EOR potential. The previous results were published in the February 1977 Oil Report and again in the September 1978 Oil Report. All established pools have been re-examined to take into account recent developments in EOR techniques and the evidence provided at this inquiry. This review provides an estimate of the quantity of crude oil that could be physically recovered by application of known enhanced recovery techniques if there were no economic constraints. This physical limit is an upper limit which is often referred to as the technical potential. The Board's estimate of technical potential for enhanced recovery of light crude oil is shown in the final column of Table 10-7. This estimate shows that enhanced recovery techniques have the potential to add more than 500 million cubic metres to the light crude oil reserves.

Further studies were carried out to establish the recoverable potential for each of the Board's four cases. These studies took into account economic considerations, uncertainties with regard to obtaining the necessary approvals, and also technological uncertainty related to oil recovery from EOR projects. In the low case the EOR technical potential was assessed to be 25 percent

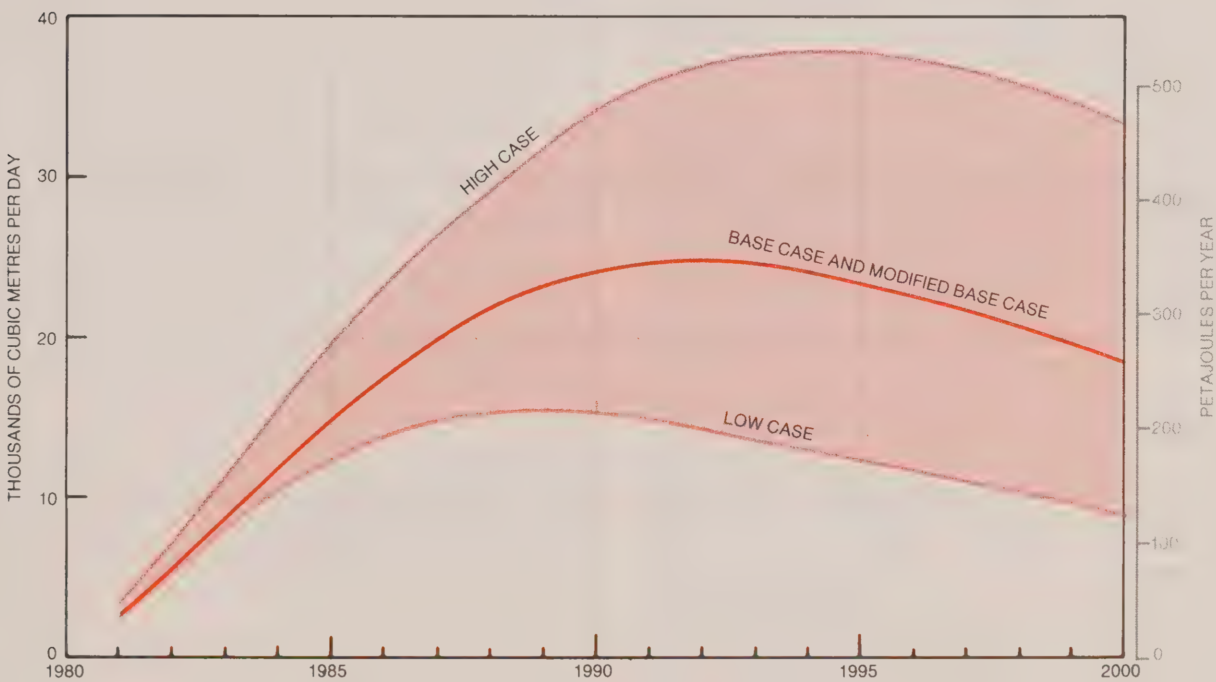

Figure 10-20 Productive Capacity from New Discoveries of Light Crude Oil
NEB Forecast

Table 10-7

POTENTIAL FOR RECOVERABLE RESERVES ADDITIONS FROM ENHANCED RECOVERY OF LIGHT CRUDE OIL
NEB Estimate
(millions of cubic metres)

	Low	Base	Modified Base	High	Technical Potential
Infill Drilling	4.2	8.5	8.5	10.2	10.2
Waterflooding	31.2	68.7	68.7	74.9	74.9
Thermal[1]	—	—	—	—	4.5
Chemical Flooding	—	3.5	9.1	11.1	15.7
Miscible Flooding	—	83.4	216.1	269.8	421.9
TOTAL	35.4	164.1	302.4	366.0	527.2

[1] Economic potential not evaluated.

lower than in the other three cases because of the uncertainties involved. Production from the proposed waterflood at Norman Wells was not included in the low case.

The dominant factor in reserves additions from EOR is the crude oil price or more specifically the netback that remains after paying taxes and royalties. The NEP recognized this by providing incentive pricing for tertiary oil. This incentive price would be approximately $189 per cubic metre for a company producing 15 degree crude oil through approved tertiary methods. In both the low case and the base case, the Board has used this price which should result in a netback of between $80 and $125 per cubic metre for EOR projects in Alberta. Because the definition of the incentive price includes a reference to 15 degree crude oil, the Board has assumed that a higher price could apply to better quality crude oil. For its modified base case the Board has assumed a price for light oil equal to the oil sands reference price of $239 per cubic metre. This price assumption, resulting in a producer netback of between $100 and $150 per cubic metre, yields about one-half of the technical potential. For its high case the Board used the world price for light sweet crude oil of $300 per cubic metre. This would increase producer netback in Alberta to between $125 and $200 per cubic metre and would yield about two-thirds of the technical potential.

Another factor that has to be considered when evaluating the economics of tertiary projects is the method that is used to determine the proportion of production that will qualify for payment of the incentive price. The NEP did not define this method. Submittors generally favoured a method based on remaining reserves. The portion of the production that would qualify for the higher price would be calculated by dividing the reserves additions from EOR by the total remaining reserves, including reserves attributed to EOR. The Board has assumed that this method would apply in all cases, except in the low case. For the low case the Board has assumed that the incentive price would be paid on the basis of incremental production. The incremental production method requires a forecast of future production without EOR and only oil production in excess of this forecast would qualify for the incentive. Under this method, production from most projects would receive the additional revenue later in the life of the pool, whereas the bulk of the investments are made when the EOR scheme is being implemented.

Another measure introduced by the NEP was the tax on LPG production. The Board has assumed that LPG used for miscible flood projects would be exempt from the LPG tax.

To determine what portion of the technical potential would be economic to develop at various levels of producer netback, the Board selected 38 pools for detailed economic analysis. The pools were selected as representative of the tertiary potential in conventional reservoirs. The economic analysis of these pools was done with the assistance of a project evaluation model obtained from the Canadian Energy Research Institute (CERI). This model was modified to reflect evidence regarding the cost of tertiary projects and to incorporate fiscal measures contained in the NEP. The supply response to price, determined for the sample pools, was then applied to the total technical potential.

On the basis of this analysis, the Board estimates the potential for recoverable reserve additions from EOR of light crude as summarized in Table 10-7.

Although the Board has used price as the variable in its analysis of EOR, it recognizes that it is the netback which determines profitability. Thus lower prices combined with lower royalties and taxes could yield the same amount of oil as higher prices combined with higher royalties and taxes.

These potentials then formed the basis for the Board's productive capacity forecasts shown on Figure 10-21. For the low case, only infill drilling and waterflooding would make a contribution to supply. For the base case, the major contribution is expected to come from miscible flood projects that have been proposed or are now in the planning stage. Production from the proposed Norman Wells waterflood is forecast to increase supply in 1986.

For the modified base case, although the Board's studies show that the economic potential for EOR would be improved considerably, the production response is expected to be only slightly above the base case for the following reasons:

—All projects require significant lead times for project design, regulatory approvals and construction of the necessary facilities.

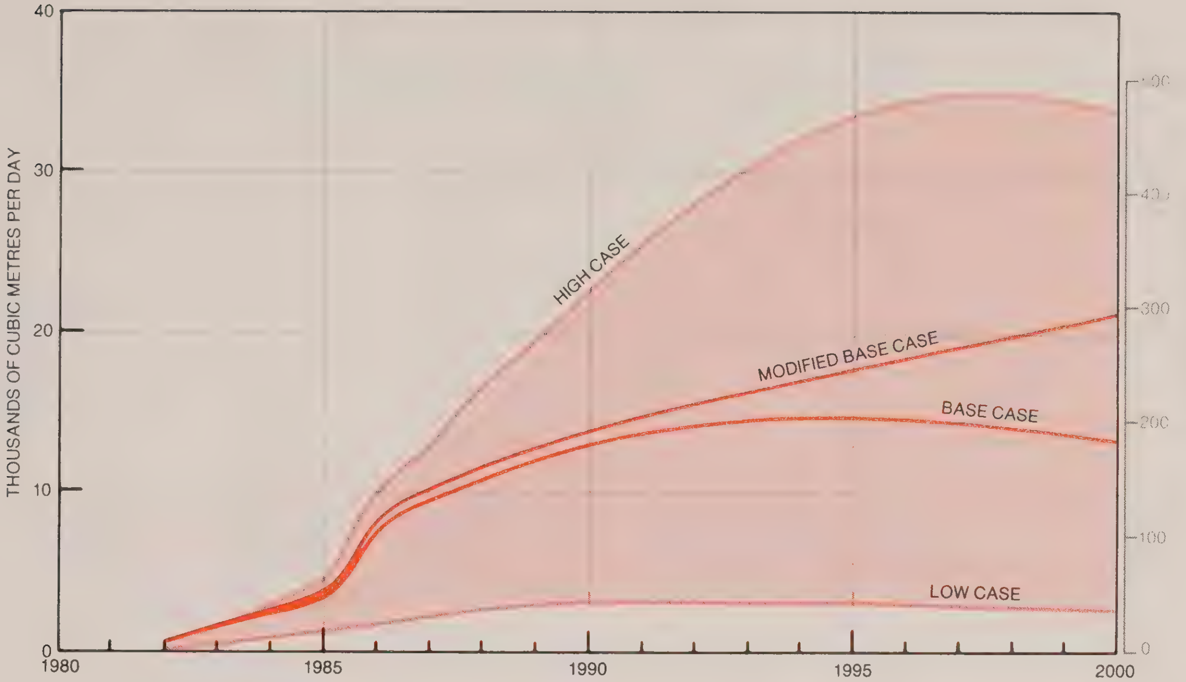

Figure 10-21 Productive Capacity from Enhanced Recovery of Established Reserves of Light Crude Oil NEB Forecast (as of December 31, 1979)

—Producers will initially submit proposals on those projects that show the best prospects for technical and economic success.

—Producers will want to see how these projects perform before taking additional risks on other projects.

—The supply of injection fluids is limited and a rapid implementation of EOR schemes would require recourse to more costly sources of fluids, which would in turn render these projects less economic.

For the high case the cost considerations become less relevant. Although some of the technical and manpower constraints continue, better economic returns should result in more risk taking and a more rapid implementation of projects that can afford the use of higher-priced carbon dioxide, LPG and chemicals.

Heavy Crude Oil

New Discoveries

The Board's estimate of undiscovered potential for the base case is unchanged from the 1978 Oil Report, however, discoveries in 1978 and 1979 have been subtracted to arrive at a year-end potential.

The Board's base case and modified base case estimate of remaining undiscovered potential for recoverable heavy crude oil is 80 million cubic metres. These two cases assume the same geological potential. For the low case the estimate is 40 million cubic metres and for the high case it is 125 million cubic metres. As with light crude oil, these estimates include all future reserves additions, including EOR for these discoveries.

For each case, the Board assumes that oil directed drilling will stay near 1980 levels and estimates that approximately 90 percent of the heavy crude oil potential will be realized during the forecast period. Forecast productive capacity from new discoveries of heavy crude oil is shown on Figure 10-22.

Enhanced Recovery

The Board agrees with the majority of Submittors, that only through implementation of enhanced recovery projects can the heavy crude oil potential in Western Canada be realized. The Board has also updated its previous studies for EOR from heavy crude oil in a manner similar to that used for light crude oil. The technical potential was first assessed as is shown in the final column of Table 10-8. This is the Board's estimate of the quan-

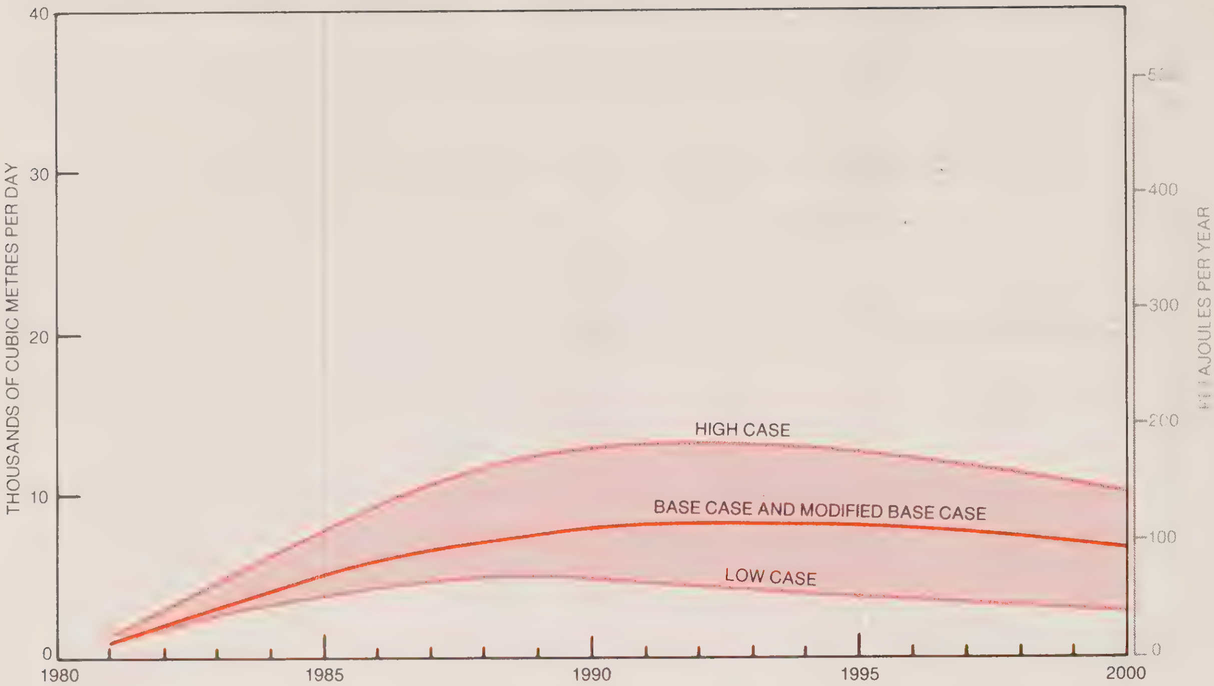

Figure 10-22 Productive Capacity from New Discoveries of Heavy Crude Oil NEB Forecast

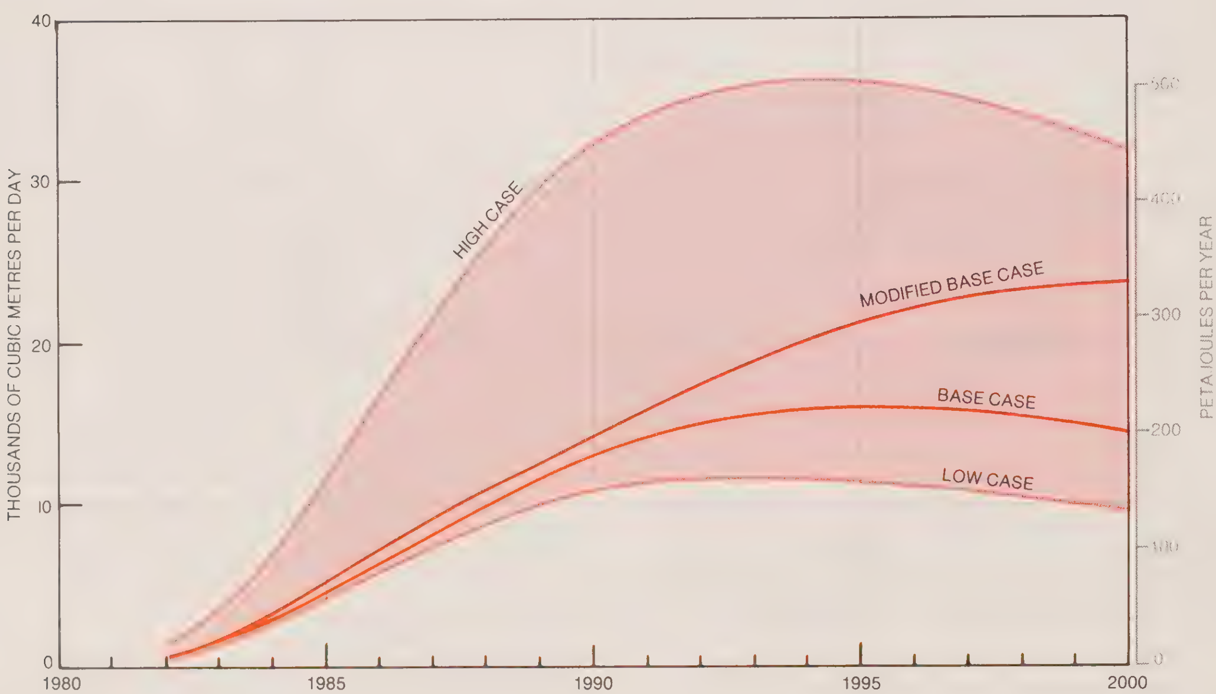

Figure 10-23 Productive Capacity from Enhanced Recovery of Established Reserves of Heavy Crude Oil NEB Forecast (as of December 31, 1979)

Table 10-8

POTENTIAL FOR RECOVERABLE RESERVES ADDITIONS FROM ENHANCED RECOVERY OF HEAVY CRUDE OIL
NEB Estimate
(millions of cubic metres)

	Low	Base	Modified Base	High	Technical Potential
Infill Drilling and Waterflooding	60.0	87.4	87.4	158.2	158.2
Chemical Flooding	—	0.6	0.6	1.8	15.0
Miscible Flooding	—	1.4	1.4	6.6	50.4
Lloydminster Area Thermal	23.8	63.6	115.0	194.8	401.3
Other Thermal	8.9	15.9	18.1	31.0	42.7
Total	92.7	168.9	222.5	392.4	667.6

tity of crude oil that could be physically recovered by application of known enhanced recovery techniques, were there no economic constraints. Enhanced recovery techniques are considered to have the potential of adding more than 650 million cubic metres of heavy crude oil to the recoverable reserves.

In order to establish the recoverable potential for each of the Board's cases, the Board took into account technical, economic and regulatory considerations as discussed in the light crude oil section. The NEP incentive price of $189 per cubic metre was used in the low, base, and modified base case. In the high case, a price of $230 per cubic metre was used to illustrate the effect of paying heavy crude oil the world price. The prices assumed by the Board for the modified base case and the high case took into consideration the expected cost of upgrading the heavy crude oil.

It was also assumed in the modified base case and high case that the federal and provincial fiscal regime as applied to Saskatchewan production would be modified to increase producer netback. Because of this assumption in the modified base case, the producer netback increased by about $20 per cubic metre over the base case. This would be about equal to the increase in netback for light crude oil when going from the base case to the modified base case.

Except for the low case, it was assumed that producers could select the most advantageous of the two methods discussed under EOR from light crude oil. In the low case the incremental production method was assumed.

With these technical and economic assumptions, and on the basis of the evidence, in particular that regarding the relationship between reserves and producer netbacks, the Board has estimated the potential for reserves additions as shown summarized in Table 10-8.

This potential formed the basis of the Board's productive capacity forecasts shown on Figure 10-23. In the low case, waterfloods are expected to dominate the EOR forecast. In the base case, a considerable contribution is expected from thermal projects currently in the planning stage. Because recoverable reserves are dependent on the level of producer netback, a significant increase in EOR potential can be realized under the assumptions of the modified base case. However, the production response to these improved economics is relatively slow for reasons that are similar to those discussed under EOR for light crude oil. The high case assumes a significant improvement in the netback and producers are expected to assume more risk.

10.2.3 *Pentanes Plus*

Views of Submittors

Pentanes plus is part of the crude oil and equivalent supply but the Submittors views are not discussed in this chapter because it is produced as a by-product of natural gas processing, and is discussed in detail with other natural gas liquids in Chapter 12.

Views of the Board

The forecast of pentanes plus supply is included in this chapter because pentanes plus is part of the crude oil and equivalent supply. A more detailed discussion of the assumptions underlying this forecast can be found in Chapter 12 which discusses the supply of all natural gas liquids.

The Board's forecast of pentanes plus production is summarized in Appendix M. This summary provides supply by gas plant, pipeline system, province and total Canada. However, only part of this supply will be available as crude oil and equivalent, because minor volumes are expected to be used in enhanced oil recovery schemes. Only the remaining available pentanes plus supply, after allowing for base case miscible fluid requirements, is included in Tables 10-14 to 10-17. These tables summarize the supply of crude oil and equivalent and are shown in Section 10.6.

The growth in the available supply of pentanes plus from the current level of 16.9 thousand cubic metres per day to a level of 17.7 thousand cubic metres per day in 1984 is attributable to an expected increase in natural gas production. The subsequent decrease in supply is related to reduced gas exports, termination of major gas cycling schemes and a gradual decrease in the pentanes plus content of produced gas, as reservoir pressures decline in older fields and solution gas supply diminishes. The decrease in pentanes plus content in the total gas supply is

aggravated by the assumption that future gas discoveries may contain less pentanes plus than the currently established reserves. This trend has been observed over the last decade.

10.3 Oil Sands Deposits

Views of Submittors

Forecasts of oil sands productive capacity were received from eleven Submittors and are compared in Figure 10-24 together with a forecast by AERCB from its 81-B report. These forecasts were based on the Submittors' estimates of the dates that production from potential oil sands projects could begin. Table 10-9 summarizes this information. There was agreement that the next three commercial projects would be the Syncrude plant expansion, Imperial's Cold Lake project and the Alsands mining project. All but one of the Submittors forecast start-up of a fourth mining project during the period 1990-1993. AERCB also predicted start-up of a fourth project in 1991. Most of these Submittors believed that the fourth project would be a proposed NOVA/Petro-Canada joint venture. Ontario concluded, in its base case scenario, that no new mining plants would be constructed after completion of the Alsands project.

Most of the Submittors who prepared estimates of production from oil sands experimental projects agreed that productive capacity would increase from current levels of two thousand cubic metres per day, to eight thousand cubic metres per day, within the forecast period. The two exceptions were Shell, which forecast 12 200 cubic metres per day by the year 2000 from experimental projects and small commercial operations; and NOVA, which believed that production from experimental pilots would contribute 15 900 cubic metres per day by 2000.

Following the announcement of the NEP, seven Submittors revised their forecasts of productive capacity from oil sands projects. The revised forecasts are presented graphically in Figure 10-25. Most Submittors felt that no new projects would start up during the forecast period under the NEP; see Table 10-10. Ontario indicated that the Cold Lake and Alsands projects would be deferred one to three years. Petro-Canada and Texaco did not change their pre-NEP forecasts since both Submittors assumed that a Federal-Provincial agreement would be reached quickly and that this agreement would be conducive to oil sands development.

The major concern of Submittors with respect to the economics of new oil sands plants under the NEP was the rate of price increase. The NEP established the oil sands reference price at \$38 per barrel (\$239/m³) for 1981 and allowed future escalation in relation to the CPI. Most Submittors felt that costs of constructing and operating oil sands plants would increase at a higher rate than the CPI. In support of this, Submittors cited the experience of the Suncor and Syncrude plants, and on the higher rate of cost inflation which has been generally experienced by the oil and gas industry. CPA presented statistics indicating an inflationary increase in oil and gas industry capital costs which averaged 14 percent per year over the period 1973 to 1978 in contrast to an increase in the GNE implicit price index of 9.6 percent per year.

Suncor's analysis of its oil sands plant costs indicated cost increases over the period 1972 to 1980 averaging 17.6 percent per year for operating costs, 19.4 percent per year for overburden removal costs and 22.2 percent per year for capital replacement costs, for an overall 20.3 percent per year annual increase in costs. The CPI was shown to have increased by 9.1 percent per year over the same period. Suncor attributed the cost increases to a gradually expanding mine area, rising maintenance and capital replacement requirements for its plant and equipment, and relatively high inflation.

Table 10-9

PROJECTED START-UP DATES OF POTENTIAL OIL SANDS PROJECTS
1980-2000
Comparison of Forecasts
Pre-NEP

	Syncrude Expansion	Cold Lake In Situ	Alsands Mining	4th Mining	2nd In Situ	5th Mining	3rd In Situ	6th Mining	7th Mining
CPA	1988	1986	1987	Five unidentified projects: 1990-200					
Dome	1995	1986	1988	1990	1993				
Gulf	1988	1987	1988	1990		1995		2000	
Imperial	1988	1986	1987	1993					
Norcen	1987	1986	1986	1990	One unidentified project every 22 years				
NOVA	1988	1987	1988	1991		1994		1997	2000
Ontario	NIL	1987	1987						
Petro-Canada	1989	1987	1987	1990	1994	1997	1999		
Shell	1988	1987	1987	Three unidentified projects: 1993, 1995, 1999					
Texaco	1985-1990	1985-1990	1985-1990	1985-1990	Two unidentified projects: 1990-1995				
Union Carbide	1985	1987	1987	1993	1990	1994	1996	1999	2000
AERCB	1989	1987	1987	Several unidentified projects: 1991-2000					

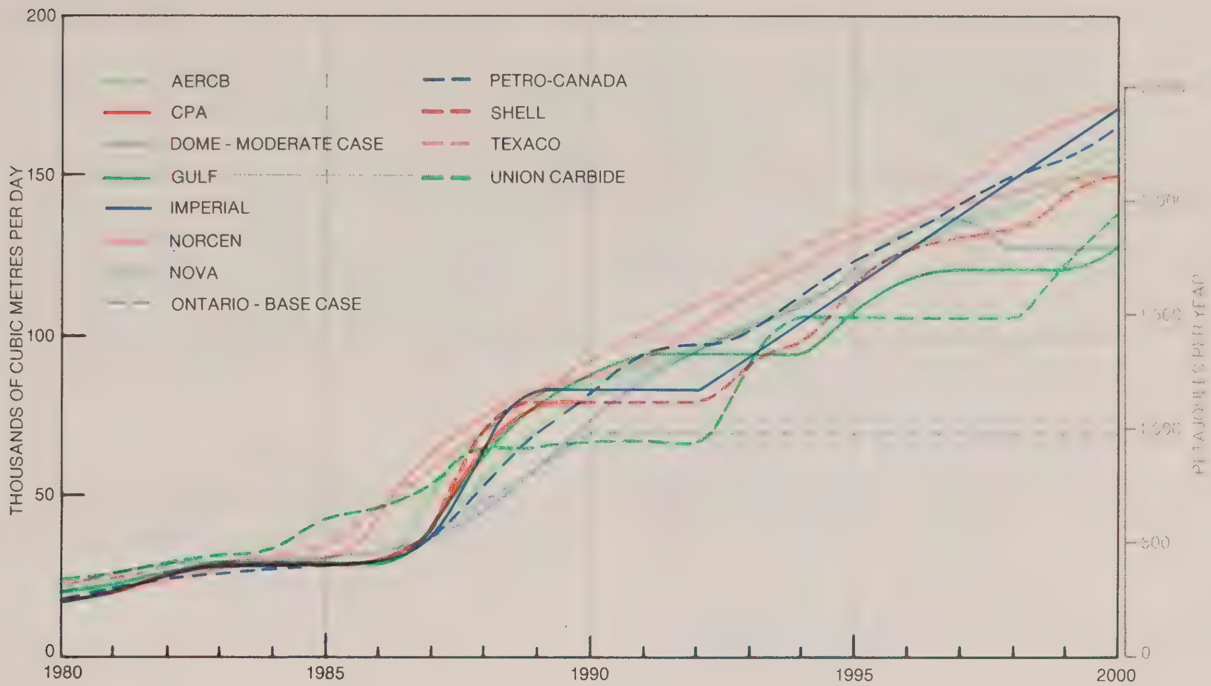

Figure 10-24 Productive Capacity from Oil Sands
Comparison of Forecasts: Pre-NEP

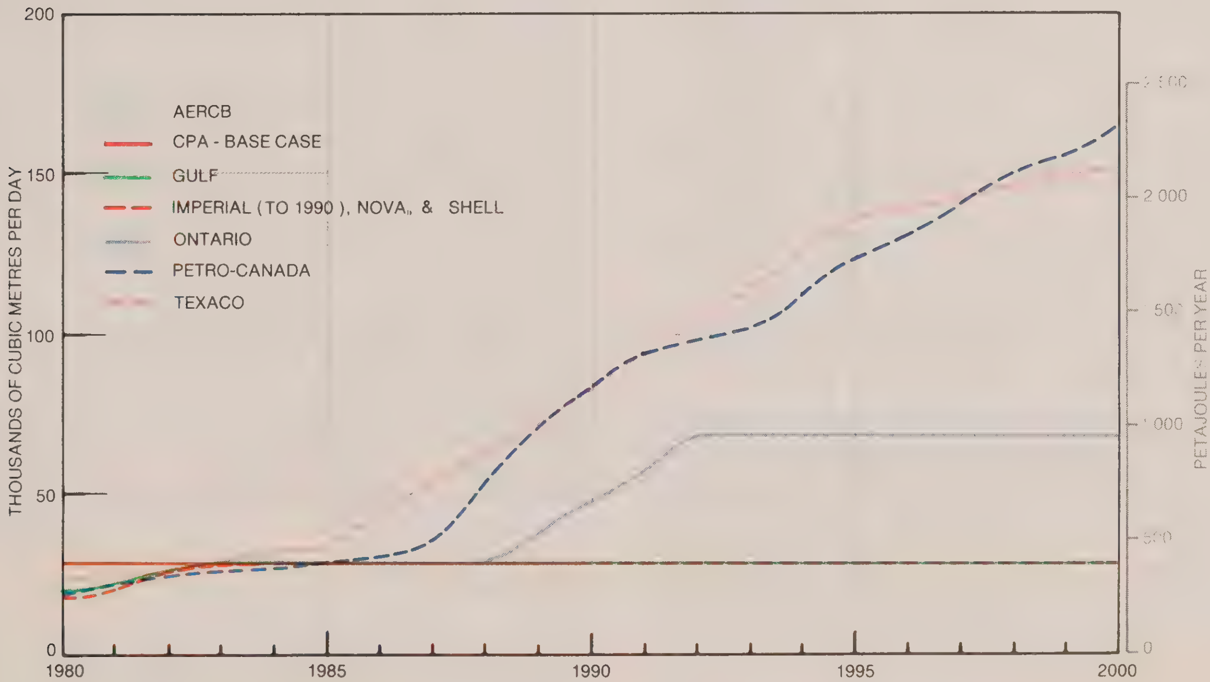

Figure 10-25 Productive Capacity from Oil Sands
Comparison of Forecasts: Post-NEP

Table 10-10

PROJECTED START-UP DATES OF POTENTIAL OIL SANDS PROJECTS
1980-2000
Comparison of Forecasts
Post-NEP

	Syncrude Expansion	Cold Lake In Situ	Alsands Mining	4th Mining	2nd In Situ	5th Mining	3rd In Situ
CPA	NIL	NIL	NIL				
Dome	—	—	—				
Gulf	NIL	NIL	NIL				
Imperial	NIL	NIL	NIL				
Norcen	—	—	—				
NOVA	NIL	NIL	NIL				
Ontario	NIL	1988-1991	1981-1991	NIL	NIL		
Petro-Canada	1989	1987	1987	1990	1994	1997	1999
Texaco	1985-1990	1985-1990	1985-1990	Two additional unidentified projects 1990-1995			
Union Carbide	—	—	—				
AERCB	NIL	NIL	NIL				

— Forecast not available.

Suncor felt that the cost inflation was a combination of international demand for oil and gas-related equipment and more localized northern Alberta inflation associated with an active oil and gas industry and a remote location. Several Submittors suggested that a price escalator closer to oil sands cost experience would improve the economic outlook for new oil sands plants, assuming that provincial project approval was received and an acceptable royalty was established.

Views of the Board

To account for uncertainties in oil sands development, the Board has again considered four possible cases.

The Board's low case assumes that there will be no agreement on energy matters between the federal and Alberta governments, and accordingly, future oil sands development approvals will not be issued. Under this assumption, the existing Suncor and Syncrude plants remain the sole source of synthetic crude oil from the oil sands.

The Board's base case reflects the pricing and fiscal measures of the NEP and current provincial policies with regard to revenue taken from the oil sands. Assumptions were made that development approvals would be issued by the Alberta government and that the NEP price of $239 per cubic metre, escalated in the future by the CPI, would prevail. Based on a detailed examination of the evidence, the Board believes it unlikely that further development of the oil sands will take place under this scenario. Therefore, oil sands production in the base case is expected to be the same as in the low case.

The Board's modified base case was developed on the basis that a resolution of the pricing and revenue sharing issues would permit oil sands development to proceed. The Board does not foresee a rate of oil sands development higher than the modified base case, therefore its high case supply forecast is the same as the modified base case for oil sands. The main reason for this is that the Board does not foresee the feasibility of accelerating the schedule of new plants, from the intervals which were assumed in the modified base case, given the constraints in manpower, specialized equipment, and environmental issues.

In the view of the Board, oil sands development could become profitable at a price of some $260 per cubic metre ($1981), provided that this price was maintained in future years in real terms and that modifications were made in royalties and taxes. At higher prices less or no modifications would be required. Therefore the Board has assumed a price range of $260 to $300 per cubic metre. The lower value approximates the present average cost of imported light and heavy oil, whereas the higher value is close to the world price for light sweet crude.

Under these conditions, the Board's forecast of oil sands production would be similar to the base case development given in the Board's 1978 Oil Report, except for the following differences in the Syncrude and Suncor expansions. The Syncrude expansion is delayed to resolve technical difficulties in both the mining and the upgrading stages. This expansion is expected to be finished in 1989. The Suncor expansion is nearly complete, and increased supply should be available in July, 1981. Production following the expansion is expected to average 8.7 thousand cubic metres per day, by the end of 1981.

The Esso Cold Lake and Shell Alsands projects are forecast to commence as outlined in the Board's 1978 Oil Report, with the provision that a satisfactory fiscal agreement can be reached between the companies and the Alberta government within the next six months.

The Board's forecasts are given in detail in Appendix N.

10.4 Frontier Areas

Views of Submittors

The majority of Submittors agreed that the major change in Canada's oil supply prospects, since the release of the 1978 NEB Oil Report, was the possibility of substantial volumes of crude oil production from Canada's frontier areas. Generally they also agreed that the frontier basins were still relatively unexplored and that forecasts of the reserves from frontier discoveries were necessarily imprecise. Many Submittors were reluctant to submit estimates of reserves or ultimate potential for these areas. The estimates which were made prior to the NEP are compared in Table 10-11.

Table 10-11

FRONTIER RESERVES POTENTIAL
(millions of cubic metres)

	Estimated Reserves Discovered to Date	Ultimate Potential
Mackenzie Delta-Beaufort Sea		
Dome	524 - 922	5 110 - 11 100
Gulf	47.7	—
NOVA	88	800
East Coast		
Dome	300	978
NOVA	134	400
Newfoundland	159	1 600
Petro-Canada	159	—

Estimates of proven and probable reserves for the Hibernia discovery off Newfoundland and the Kopanoar and Tarsiut discoveries in the Beaufort Sea are shown in Table 10-12.

Table 10-12

POTENTIAL RECOVERABLE RESERVES
(millions of cubic metres)

	Hibernia	Kopanoar	Tarsiut
Dome	191	290 - 590	160 - 250
Gulf	—	—	31.8
Newfoundland	159	—	—
NOVA	134	88	—
Petro-Canada	159	—	—

Most Submittors agreed that attempting to assess crude oil productive capacity from frontier areas, was a difficult exercise, subject to a high degree of uncertainty. To demonstrate this uncertainty, some Submittors provided a range of production scenarios for frontier basins. Others confined their analysis to known discoveries such as Hibernia and Kopanoar, because they believed it was premature to predict basin production potential on the basis of limited current data. For comparison purposes, Submittors' supply estimates for the east coast region, and the Mackenzie Delta-Beaufort Basin are given in Table 10-13 and Figures 10-26 and 10-27.

Post-NEP opinion concerning frontier development generally reflected each Submittor's position relative to key NEP conditions and the effect these would have on their future operating plans. Most agreed that a specified price was a prerequisite to the development of frontier resources. However, all Submittors considered that the conventional oil pricing schedule would be inadequate to sustain frontier development. Petro-Canada thought that development of Hibernia could be possible at the conventional oil price if costs could be kept low and reserves were proven to be adequate. Chevron felt that Hibernia development may not be viable even at the world price, depending on assumptions concerning reserves and costs.

Table 10-13

FRONTIER CRUDE OIL PRODUCTIVE CAPACITY
ESTIMATED YEAR OF FIRST PRODUCTION

	Year
Beaufort Sea	
Dome	1985
Gulf	1988
Imperial	1991
NOVA	1992
Ontario	1987
East Coast	
Dome	1986
Gulf	1986
Imperial	1988
Mobil	1986
Newfoundland	1985
NOVA	1987
Ontario	1985
Petro-Canada	1986
Frontiers	
CPA	1985-1990
Shell	1988-1993

It was Petro-Canada's contention that the adverse effect of the NEP tax conditions would be more than offset by the Petroleum Incentives Program for frontier investments by Canadian controlled companies. It was also Petro-Canada's opinion, supported by Dome, that fiscal terms and regulations affecting frontier development under the NEP compared favourably with those under Norwegian and British fiscal regimes. Shell believed that exploration on Canada lands would be impeded by the government option to take a 25 percent carried interest in any discovery and considered this provision to be confiscatory in nature.

Newfoundland and Ontario expressed some concern that the federal government's new fiscal conditions and Canadianization of oil and gas exploration would adversely affect the motivation of the major oil companies to maintain a high profile in frontier

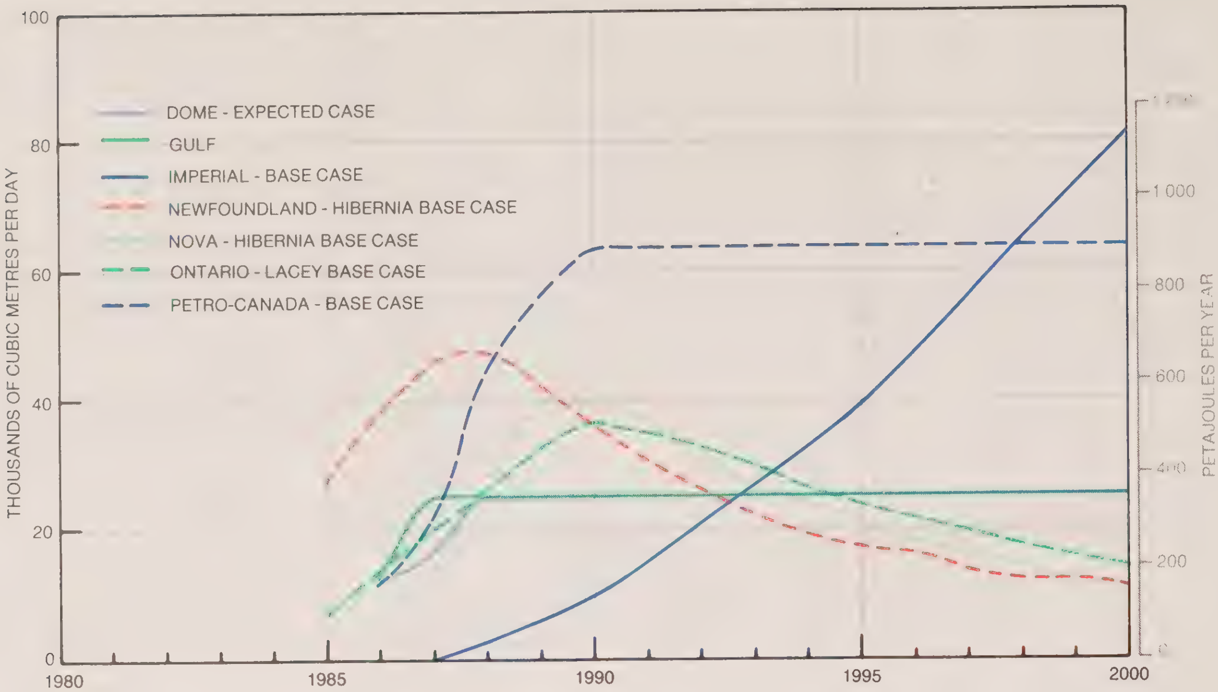

Figure 10-26 Productive Capacity from East Coast Offshore Development
Comparison of Forecasts: Pre-NEP

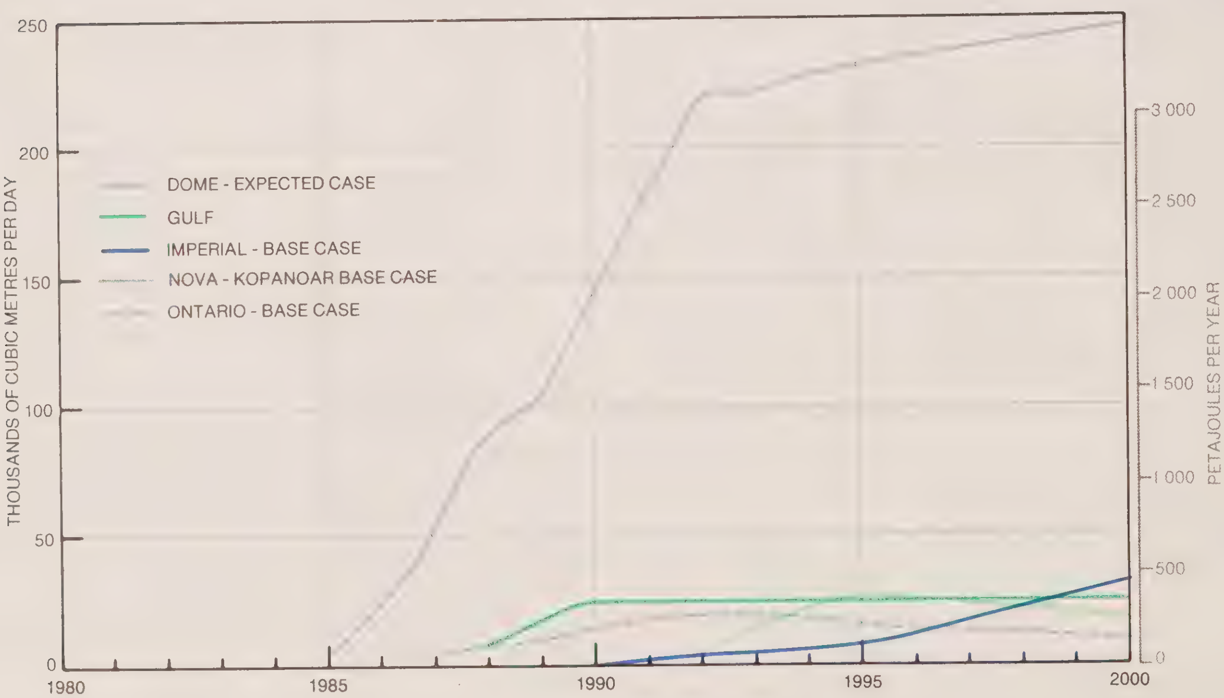

Figure 10-27 Productive Capacity from Mackenzie Delta-Beaufort Sea Development
Comparison of Forecasts: Pre-NEP

development. The expected result would be that the pace of exploration and development off Canada's east coast would slacken. According to CPA, if there were no changes in the provisions of the NEP, frontier oil activity would diminish and development would be difficult to initiate and sustain. Mobil was concerned with the new taxes, the creation of uncertainty over its ultimate company interest, and the failure to specify a price for offshore production. These concerns led Mobil to reduce its 1981 exploration program. Because of prior commitments to a delineation drilling program, Mobil did not foresee any significant delay in developing the Hibernia field. In Chevron's opinion, the incentives in the NEP were inadequate to stimulate frontier exploration, even by companies with 75 percent or greater Canadian ownership.

Submittors emphasized the need for further study of the reservoir characteristics, environmental conditions and design of facilities before confidence could be placed in conclusions concerning the economics of producing oil from the Hibernia field. Uncertainty was also seen to be introduced by jurisdictional questions.

Several Submittors presented estimates of the capital cost of developing the Hibernia field on the assumption that recoverable reserves were 150 million cubic metres and that floating production systems would be used. These estimates were in the range of $4 billion (1980 dollars). Newfoundland considered the alternative of a permanent production structure with oil and gas pipelines to shore. This system was estimated to have a capital cost of $8.1 billion (1980 dollars). Operating cost estimates varied from $10.50 per cubic metre for a permanent production structure to a range of $19 to $38 per cubic metre which Chevron indicated was typical of North Sea costs.

Dome presented an analysis of Beaufort Sea oil and gas development potential which showed that the NEP would delay Beaufort Sea development by one year and that world prices would be required to permit oil development to proceed. Dome indicated that it intended to complete a $480 million exploration program for 1981. The development cost for the Kopanoar east lobe was estimated at $4 billion (1980 dollars). These costs were based on developing a production potential of 80 thousand cubic metres per day. A transportation tariff of $25 per cubic metre was estimated for delivery of the oil to Eastern Canada by ice-breaking tanker.

Dome estimated that three major oil fields would be discovered and developed in the Beaufort Sea over the next decade as well as major natural gas reserves. Total expenditures to develop these reserves were projected to be $25 billion for oil and $15 billion for natural gas.

Views of the Board

The Board recognizes that frontier sedimentary basins are still in the immature stage of the exploration process and that estimating reserves and productive capacity from these relatively unexplored areas is speculative. Nevertheless, significant oil discoveries have been made on the Grand Banks offshore from Newfoundland and oil has been encountered in several structures in the Arctic. The Board is encouraged by these discoveries and acknowledges the potential for additional discoveries.

In its assessment of the east coast offshore region, the Board believes that sufficient drilling has been done on the Hibernia structure in the Jeanne d'Arc Basin to justify inclusion of 50 million cubic metres of crude oil in the established reserves category for all four cases.

No reserves additions are included in the low and base case. However, the Board is encouraged by the geological potential of the Hibernia area, and is optimistic that reserves will appreciate significantly. Consequently, the Board has assumed reserves additions of 50 million cubic metres for this area in the modified base case and 100 million cubic metres in the high case.

A number of Submittors presented preliminary studies of the economic viability of producing oil from the Hibernia area. From these studies it is apparent that the supply cost of this oil depends heavily on the size of the reserves, the producing characteristics of the reservoir and the type of production facilities chosen to bring the reserves on production. From its analysis, the Board concludes that base case reserves and expected productive capacity would be sufficient to support a viable operation based on a floating production platform with on-site tanker loading facilities. However, it would appear from the Board's analysis of the evidence that considering established reserves of only 50 million cubic metres, a price approaching $300 per cubic metre, which is the current price of imported light sweet crude oil, would be required.

The Board's low case assumes that development of the Hibernia field will be delayed beyond the forecast period because of high cost estimates.

For the base case productive capacity forecast the Board assumes that Hibernia production from established reserves will commence either in late 1986 or early 1987 and reach a level of 12 thousand cubic metres per day by 1989. Production commences to decline in 1995.

In the modified base case, production decline from the established reserves is expected to be offset by production from reserves additions which will increase total production to 17 thousand cubic metres per day by 1998 before production starts to decline.

In the high case, reserves additions are assumed to have similar reservoir characteristics as encountered in previous wells, allowing a rapid increase in productive capacity to 32 thousand cubic metres per day in 1990. Further additions to reserves are assumed to be sufficient to sustain this level of production throughout the forecast period.

As for the Mackenzie Delta-Beaufort Sea area the Board does not consider that sufficient delineation drilling has been conducted to include any crude oil from it in the established category. However, the Board recognizes that exploratory wells at Kopanoar, Tarsiut and Issungnak have indicated the possibility of significant oil reservoirs. The Board's high case reflects this possibility. In this scenario the Board assumed that production

would be transported by icebreaking tankers from the Beaufort Sea to the east coast and that production would commence at four thousand cubic metres per day in 1990 and reach 32 thousand cubic metres per day by 1993.

Regarding the possible effects of the measures contained in the NEP on frontier exploration and development, some companies which did not qualify for incentive payments under the NEP indicated a reduction in activity. However, frontier investments by Canadian companies should increase over time to offset this possible reduction. The pace of exploration in the frontier areas will be determined largely by the degree of exploration success. The Board agrees with most Submittors that producers should be able to estimate their expected netback and they should know with certainty what jurisdiction they will be dealing with, in order for current discoveries to be developed and to encourage future exploration activities.

10.5 Coal Liquefaction

Views of Submittors

Most Submittors addressing the topic of coal liquefaction suggested that it would not materially contribute to Canada's supply before 2000, principally because of economic factors.

However, the Coal Assn. projected that coal use for the production of synthetic fuels would climb from some five million tonnes in 1990 to 18.8 million tonnes in the year 2000. It further stated that if the domestic oil prices were raised to world levels it would soon become economic to convert coal to liquid fuels.

Shell stated that although its basic forecast assumed that no coal liquefaction plants would be built before the year 2000, the possibility existed that a demonstration commercial scale plant in western Canada could be built by 1990-95. This possibility would require continued development of the process, a favourable economic climate and government co-operation.

NOVA stated that the coal deposits in Alberta were suitable for strip mining and were of sufficient size to make Alberta a prime target for early study of liquefaction options. However, NOVA suggested that it might be more desirable to save the less costly reserves which can be strip-mined for the production of electricity.

DEVCO submitted that it was investigating the conversion of Cape Breton coal to synthetic fuel. This project would use 65.5 petajoules of coal per year in the period 1990 to 1995 increasing to 98.0 petajoules per year by 2000.

Union Carbide testified that it did not expect coal liquefaction to become an alternative source of petrochemical feedstocks in the period under consideration.

Mobil suggested that coal could provide the basic feedstock to a plant producing alcohol for conversion to gasoline using its patented process. At present United States gasoline prices, Mobil testified that process was not economic but it expected that within five years the price-cost differential could be eliminated. This figure was subsequently modified to some ten years.

British Columbia stated that by using natural gas reserves it may be able to produce liquids from coal more cheaply than others using only coal in the conversion process. British Columbia submitted that it had recently contracted for a pre-feasibility study of coal liquefaction at Hat Creek. The study would focus on the engineering and economic aspects of the project.

Views of the Board

The Board believes that it is unlikely that coal-derived synthetic liquid fuels will contribute significantly to Canada's energy requirements during the forecast period because in Canada, at least, other supply options will almost definitely be less costly. However, should the cost of coal-derived liquids fall below the international price of crude oil before the end of the forecast period a synthetic fuel industry, based on coal, could be developed in several countries including Canada.

10.6 Summary of Productive Capacity Forecasts

Views of Submittors

The productive capacity forecasts for crude oil and equivalent are summarized on Figure 10-28. The forecasts were similar until 1985, but diverge significantly thereafter from about 50 thousand cubic metres per day to about 175 thousand cubic metres per day by the year 2000.

Seven Submittors provided revised forecasts showing the impact of the NEP. These forecasts are summarized on Figure 10-29. CPA and Imperial provided a forecast for only ten years. CPA showed a reduction in supply of 50 and 160 thousand cubic metres per day in 1985 and 1990 respectively, whereas Imperial showed reductions of 30 and 95 thousand cubic metres per day in those years. Shell showed reductions of 50, 110 and 265 thousand cubic metres per day in respectively 1985, 1990 and 2000, while Gulf and Texaco showed only minor reductions based on the assumption that a compromise would be reached between the Provinces and the federal Government.

Petro-Canada did not show any changes and Ontario showed a small reduction in supply in the first half of the forecast period as it also assumed that a compromise would be reached on the NEP. Petro-Canada clarified its position by referring to grants which would be available for frontier exploration. Petro-Canada testified that its cash flow was adversely affected by the increased level of taxation, but that the availability of grants could increase cash availability for reinvestment by 25 percent over pre-NEP forecasts because of Petro-Canada's heavy commitments in the frontier. When questioned on possible reduction in supply from exploration in the Western Canada basin, Petro-Canada replied that marginal prospects would be dropped but the best prospects would still be drilled.

Views of the Board

The Board's assessment of the contribution from each supply source has been aggregated and the base case and modified base case are compared with Submittors' forecasts in Figure 10-29. Tables 10-14 to 10-17 provide a summary of all four supply forecasts by component and by grade of crude oil. Figures

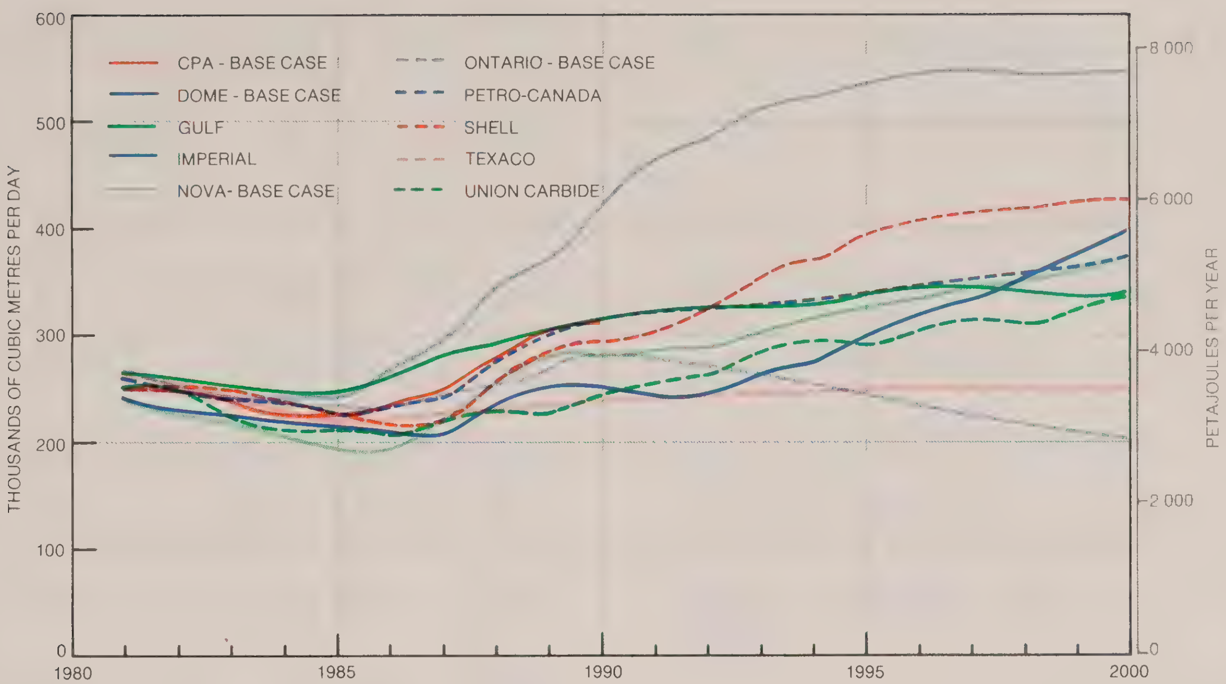

Figure 10-28 Productive Capacity of Crude Oil and Equivalent
Comparison of Forecasts: Pre-NEP

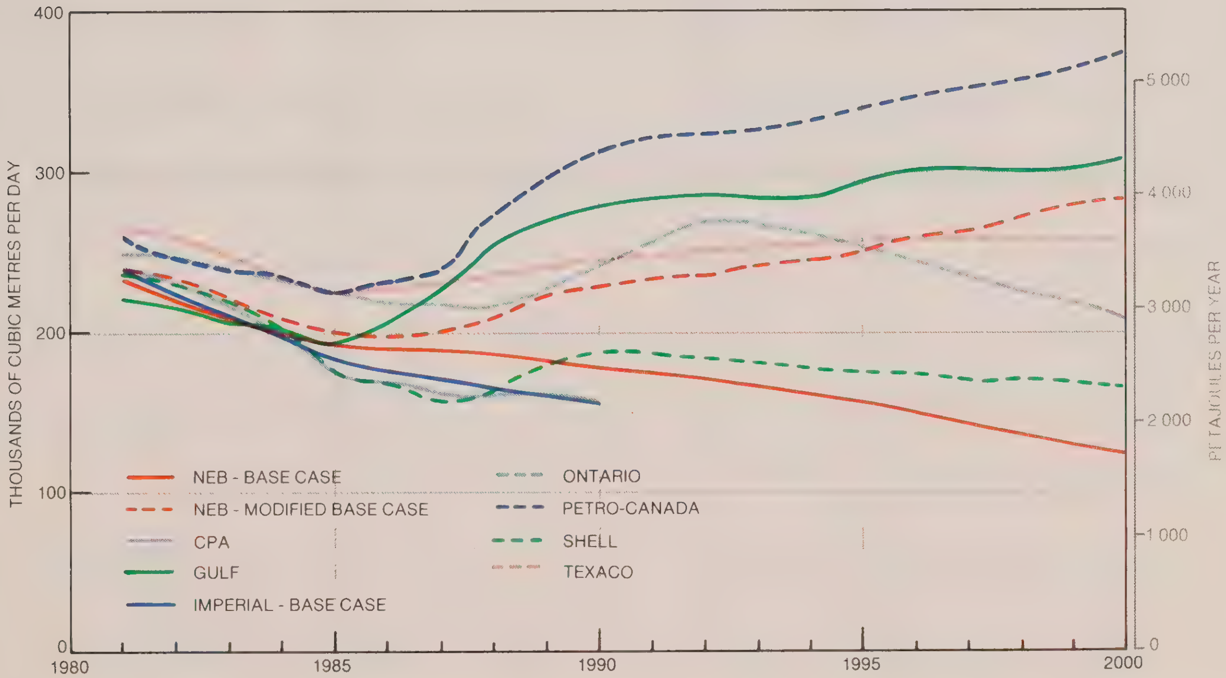

Figure 10-29 Productive Capacity of Crude Oil and Equivalent
Comparison of Forecasts: Post-NEP

Table 10-14

PRODUCTIVE CAPACITY OF CRUDE OIL AND EQUIVALENT

Low Case

$10^3m^3/d$

	Light Crude Oil and Equivalent							Heavy Crude Oil						Total Crude Oil and Equivalent						
	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands (Synthetic)	Frontier	Upgraded Heavy	Sub-Total	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands	Upgrader Feedstock	Sub-Total	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands	Frontier	Upgrading Loss	Total
1981	164.9	2.7	14.9	20.0	—	—	202.5	26.5	0.9	2.0	2.0	—	31.4	191.4	3.6	16.9	22.0	—	—	233 9
1982	146.4	5.7	15.5	25.0	—	—	192.6	21.7	2.1	1.8	3.0	—	28.6	168.1	7.8	17.3	28.0	—	—	221.2
1983	125.2	8.7	15.6	28.0	—	—	177.5	20.0	3.8	1.9	4.0	—	29.7	145.2	12.5	17.5	32.0	—	—	207.2
1984	109.0	11.4	15.7	29.0	—	—	165.1	18.6	5.9	2.0	4.0	—	30.5	127.6	17.3	17 7	33.0	—	—	195.6
1985	96.0	13.5	14.5	29.0	—	—	153.0	17.3	8.2	2.1	5.0	—	32.6	113.3	21.7	16.6	34.0	—	—	185.6
1986	84.5	15.5	13.8	29.0	—	—	142.8	16.2	10.2	2.2	5.0	—	33.6	100.7	25.7	16.0	34.0	—	—	176.4
1987	74.6	17.7	12.5	29.0	—	—	133.8	15.2	12.0	2.2	5.0	—	34.4	89.8	29.7	14.7	34.0	—	—	168.2
1988	66.3	18.1	11.2	29.0	—	—	124.6	14.3	13.8	2.3	5.0	—	35.4	80.6	31.9	13.5	34.0	—	—	160.0
1989	59.2	18.4	9.4	29.0	—	—	116.0	13.6	15.0	2.3	5.0	—	35.9	72.8	33.4	11.7	34.0	—	—	151.9
1990	52.9	18.5	8.0	29.0	—	—	108.4	12.9	15.8	2.3	5.0	—	36.0	65.8	34.3	10.3	34.0	—	—	144.4
1991	47.6	18.2	7.4	29.0	—	—	102.2	12.1	16.0	2.3	5.0	—	35.4	59.7	34.2	9.7	34.0	—	—	137 6
1992	43.0	17.6	7.1	29.0	—	—	96.7	11.3	16.0	2.2	5.0	—	34.5	54.3	33.6	9.3	34.0	—	—	131.2
1993	39.0	16.9	7.0	29.0	—	—	91.9	10.3	15.8	2.1	5.0	—	33.2	49.3	32.7	9.1	34.0	—	—	125.1
1994	35.2	16.2	7.1	29.0	—	—	87.5	9.4	15.5	2.1	5.0	—	32.0	44.6	31.7	9.2	34.0	—	—	119.5
1995	32.0	15.6	7.5	29.0	—	—	84.1	8.6	15.1	2.0	5.0	—	30.7	40.6	30.7	9.5	34.0	—	—	114.8
1996	29.3	14.8	7.8	29.0	—	—	80.9	7.8	14.6	1.9	5.0	—	29.3	37.1	29.4	9.7	34.0	—	—	110.2
1997	26.8	14.0	7.9	29.0	—	—	77.7	6.9	14.1	1.8	5.0	—	27.8	33.7	28.1	9.7	34.0	—	—	105.5
1998	24.5	13.2	7.9	29.0	—	—	74.6	6.1	13.5	1.7	5.0	—	26.3	30.6	26.7	9.6	34.0	—	—	100.9
1999	22.5	12.5	7.6	29.0	—	—	71.6	5.5	12.9	1.6	5.0	—	25.0	28.0	25.4	9.2	34.0	—	—	96.6
2000	20.7	11.7	7.4	29.0	—	—	68.8	4.9	12.3	1.5	5.0	—	23.7	25.6	24.0	8.9	34.0	—	—	92.5

Table 10-15

PRODUCTIVE CAPACITY OF CRUDE OIL AND EQUIVALENT

Base Case

$10^3m^3/d$

	Light Crude Oil and Equivalent							Heavy Crude Oil						Total Crude Oil and Equivalent						
	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands (Synthetic)	frontier	Upgraded Heavy	Sub-Total	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands	Upgrader Feedstock	Sub-Total	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands	Frontier	Upgrading Loss	Total
1981	164.9	2.7	14.9	20.0	—	—	202.5	26.5	0.9	2.0	2.0	—	31.4	191.4	3.6	16.9	22.0	—	—	233.9
1982	146.4	6.3	15.4	25.0	—	—	193.1	21.7	2.5	1.9	3.0	—	29.1	168.1	8.8	17.3	28.0	—	—	222.2
1983	125.2	10.5	15.5	28.0	—	—	179.2	20.0	4.7	2.0	4.0	—	30.7	145.2	15.2	17.5	32.0	—	—	209.9
1984	109.0	14.6	15.7	29.0	—	—	168.3	18.6	7.1	2.0	4.0	—	31.7	127.6	21.7	17.7	33.0	—	—	200.0
1985	96.0	18.5	14.4	29.0	—	—	157.9	17.3	9.6	2.2	5.0	—	34.1	113.3	28.1	16.6	34.0	—	—	192.0
1986	84.5	25.3	13.7	29.0	1.2	—	153.7	16.2	12.2	2.3	5.0	—	35.7	100.7	37.5	16.0	34.0	1.2	—	189.4
1987	74.6	29.4	12.3	29.0	7.0	—	152.3	15.2	14.9	2.4	5.0	—	37.5	89.8	44.3	14.7	34.0	7.0	—	189.8
1988	66.3	32.8	11.6	29.0	10.0	7.0	156.7	14.3	17.3	1.9	5.0	(8.0)	30.5	80.6	50.1	13.5	34.0	10.0	(1.0)	187.2
1989	59.2	35.5	9.7	29.0	12.0	7.0	152.4	13.6	19.3	2.0	5.0	(8.0)	31.9	72.8	54.8	11.7	34.0	12.0	(1.0)	184.3
1990	52.9	37.4	8.2	29.0	12.0	7.0	146.5	12.9	20.9	2.1	5.0	(8.0)	32.9	65.8	58.3	10.3	34.0	12.0	(1.0)	179.4
1991	47.6	38.6	7.6	29.0	12.0	7.0	141.8	12.1	22.4	2.1	5.0	(8.0)	33.6	59.7	61.0	9.7	34.0	12.0	(1.0)	175.4
1992	43.0	38.9	7.1	29.0	12.0	7.0	137.0	11.3	23.3	2.2	5.0	(8.0)	33.8	54.3	62.2	9.3	34.0	12.0	(1.0)	170.8
1993	39.0	39.2	7.0	29.0	12.0	7.0	133.2	10.3	23.9	2.1	5.0	(8.0)	33.3	49.3	63.1	9.1	34.0	12.0	(1.0)	166.5
1994	35.2	38.8	7.1	29.0	12.0	7.0	129.1	9.4	24.1	2.1	5.0	(8.0)	32.6	44.6	62.9	9.2	34.0	12.0	(1.0)	161.7
1995	32.0	38.1	7.5	29.0	11.8	7.0	125.4	8.6	24.1	2.0	5.0	(8.0)	31.7	40.6	62.2	9.5	34.0	11.8	(1.0)	157.1
1996	29.3	37.3	7.7	29.0	8.8	7.0	119.1	7.8	23.7	2.0	5.0	(8.0)	30.5	37.1	61.0	9.7	34.0	8.8	(1.0)	149.6
1997	26.8	36.1	7.8	29.0	6.6	7.0	113.3	6.9	23.3	1.9	5.0	(8.0)	29.1	33.7	59.4	9.7	34.0	6.6	(1.0)	142.4
1998	24.5	34.9	7.8	29.0	5.0	7.0	108.2	6.1	22.7	1.8	5.0	(8.0)	27.6	30.6	57.6	9.6	34.0	5.0	(1.0)	135.8
1999	22.5	33.5	7.5	29.0	3.7	7.0	103.2	5.5	22.0	1.7	5.0	(8.0)	26.2	28.0	55.5	9.2	34.0	3.7	(1.0)	129.4
2000	20.7	32.0	7.3	29.0	2.8	7.0	98.8	4.9	21.1	1.6	5.0	(8.0)	24.6	25.6	53.1	8.9	34.0	2.8	(1.0)	123.4

Table 10-16

PRODUCTIVE CAPACITY OF CRUDE OIL AND EQUIVALENT
Modified Base Case
$10^3 m^3/d$

	Light Crude Oil and Equivalent							Heavy Crude Oil						Total Crude Oil and Equivalent						
	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands (Synthetic)	Frontier	Upgraded Heavy	Sub-Total	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands	Upgrader Feedstock	Sub-Total	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands	Frontier	Upgrading Loss	Total
1981	165.6	2.7	14.5	20.0	—	—	202.8	31.2	0.9	2.4	2.0	—	36.5	196.8	3.6	16.9	22.0	—	—	239.3
1982	149.1	6.3	14.9	25.0	—	—	195.3	28.4	2.5	2.4	3.0	—	36.3	177.5	8.8	17.3	28.0	—	—	231.6
1983	130.0	10.5	15.1	28.0	—	—	183.6	25.6	4.8	2.4	4.0	—	36.8	155.6	15.3	17.5	32.0	—	—	220.4
1984	113.3	14.8	15.3	29.0	—	—	172.4	23.0	7.6	2.4	4.0	—	37.0	136.3	22.4	17.7	33.0	—	—	209.4
1985	99.7	18.8	14.1	29.0	—	—	161.6	20.7	10.3	2.5	5.0	—	38.5	120.4	29.1	16.6	34.0	—	—	200.1
1986	88.3	25.9	14.0	29.0	1.2	7.0	165.4	18.7	13.2	2.0	5.0	(8.0)	30.9	107.0	39.1	16.0	34.0	1.2	(1.0)	196.3
1987	78.1	30.1	12.6	34.0	7.0	7.0	168.8	16.8	15.9	2.1	5.0	(8.0)	31.8	94.9	46.0	14.7	39.0	7.0	(1.0)	200.6
1988	69.4	33.6	11.4	44.0	10.0	7.0	175.4	15.2	18.3	2.1	5.0	(8.0)	32.6	84.6	51.9	13.5	49.0	10.0	(1.0)	208.0
1989	61.9	36.4	9.6	63.0	12.0	7.0	189.9	13.7	20.3	2.1	5.0	(8.0)	33.1	75.6	56.7	11.7	68.0	12.0	(1.0)	223.0
1990	55.4	38.3	8.1	75.0	12.0	7.0	195.8	12.5	22.3	2.2	5.0	(8.0)	34.0	67.9	60.6	10.3	80.0	12.0	(1.0)	229.8
1991	49.9	39.8	7.5	81.0	12.0	7.0	197.2	11.3	24.1	2.2	5.0	(8.0)	34.6	61.2	63.9	9.7	86.0	12.0	(1.0)	231.8
1992	45.1	40.4	7.0	88.0	12.0	7.0	199.5	10.2	26.0	2.3	5.0	(8.0)	35.5	55.3	66.4	9.3	93.0	12.0	(1.0)	235.0
1993	40.9	41.0	6.8	98.0	12.0	7.0	205.7	9.3	27.4	2.3	5.0	(8.0)	36.0	50.2	68.4	9.1	103.0	12.0	(1.0)	241.7
1994	36.9	41.3	6.8	104.0	12.0	7.0	208.0	8.4	28.5	2.4	5.0	(8.0)	36.3	45.3	69.8	9.2	109.0	12.0	(1.0)	244.3
1995	33.6	41.4	7.1	112.0	13.0	7.0	214.1	7.6	29.4	2.4	5.0	(8.0)	36.4	41.2	70.8	9.5	117.0	13.0	(1.0)	250.5
1996	30.7	41.3	7.3	120.0	15.8	7.0	222.1	6.9	30.0	2.4	5.0	(8.0)	36.3	37.6	71.3	9.7	125.0	15.8	(1.0)	258.4
1997	28.1	41.0	7.4	126.0	16.6	7.0	226.1	6.2	30.5	2.3	5.0	(8.0)	36.0	34.3	71.5	9.7	131.0	16.6	(1.0)	262.1
1998	25.7	40.7	7.4	139.0	17.0	7.0	236.8	5.5	30.7	2.2	5.0	(8.0)	35.4	31.2	71.4	9.6	144.0	17.0	(1.0)	272.2
1999	23.6	40.3	7.0	150.0	15.7	7.0	243.6	4.8	30.5	2.2	5.0	(8.0)	34.5	28.4	70.8	9.2	155.0	15.7	(1.0)	278.1
2000	21.7	39.8	6.7	158.0	14.8	7.0	248.0	4.3	30.2	2.2	5.0	(8.0)	33.7	26.0	70.0	8.9	163.0	14.8	(1.0)	281.7

Table 10-17

PRODUCTIVE CAPACITY OF CRUDE OIL AND EQUIVALENT
High Case
$10^3 m^3/d$

	Light Crude Oil and Equivalent							Heavy Crude Oil						Total Crude Oil and Equivalent						
	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands (Synthetic)	Frontier	Upgraded Heavy	Sub-Total	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands	Upgrader Feedstock	Sub-Total	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands	Frontier	Upgrading Loss	Total
1981	165.6	3.7	14.5	20.0	—	—	203.8	31.2	1.4	2.4	2.0	—	37.0	196.8	5.1	16.9	22.0	—	—	240.8
1982	149.1	8.3	14.8	25.0	—	—	197.2	28.4	4.4	2.5	3.0	—	38.3	177.5	12.7	17.3	28.0	—	—	235.5
1983	130.0	13.5	14.9	28.0	—	—	186.4	25.6	8.5	2.6	4.0	—	40.7	155.6	22.0	17.5	32.0	—	—	227.1
1984	113.3	19.2	14.8	29.0	—	—	176.3	23.0	13.7	2.9	4.0	—	43.6	136.3	32.9	17.7	33.0	—	—	219.9
1985	99.7	24.7	13.5	29.0	—	—	166.9	20.7	19.9	3.1	5.0	—	48.7	120.4	44.6	16.6	34.0	—	—	215.6
1986	88.3	33.6	13.1	29.0	1.2	7.0	172.2	18.7	26.2	2.9	5.0	(8.0)	44.8	107.0	59.8	16.0	34.0	1.2	(1.0)	217.0
1987	78.1	39.9	11.5	34.0	8.2	7.0	178.7	16.8	32.3	3.2	5.0	(8.0)	49.3	94.9	72.2	14.7	39.0	8.2	(1.0)	228.0
1988	69.4	46.2	10.1	44.0	18.2	7.0	194.9	15.2	37.7	3.4	5.0	(8.0)	53.3	84.6	83.9	13.5	49.0	18.2	(1.0)	248.2
1989	61.9	51.8	8.6	63.0	29.0	14.0	228.3	13.7	42.1	3.1	5.0	(16.0)	47.9	75.6	93.9	11.7	68.0	29.0	(2.0)	276.2
1990	55.4	57.0	7.1	75.0	36.0	14.0	244.5	12.5	45.1	3.2	5.0	(16.0)	49.8	67.9	102.1	10.3	80.0	36.0	(2.0)	294.3
1991	49.9	61.7	6.4	81.0	48.0	14.0	261.0	11.3	47.3	3.3	5.0	(16.0)	50.9	61.2	109.0	9.7	86.0	48.0	(2.0)	311.9
1992	45.1	65.4	6.0	88.0	56.0	14.0	274.5	10.2	48.5	3.3	5.0	(16.0)	51.0	55.3	113.9	9.3	93.0	56.0	(2.0)	325.5
1993	40.9	68.4	5.8	98.0	64.0	14.0	291.1	9.3	49.0	3.3	5.0	(16.0)	50.6	50.2	117.4	9.1	103.0	64.0	(2.0)	341.7
1994	36.9	70.4	6.0	104.0	64.0	14.0	295.3	8.4	49.0	3.2	5.0	(16.0)	49.6	45.3	119.4	9.2	109.0	64.0	(2.0)	344.9
1995	33.6	71.5	6.4	112.0	64.0	14.0	301.5	7.6	48.6	3.1	5.0	(16.0)	48.3	41.2	120.1	9.5	117.0	64.0	(2.0)	349.8
1996	30.7	71.8	6.7	120.0	64.0	14.0	307.2	6.9	47.7	3.0	5.0	(16.0)	46.6	37.6	119.5	9.7	125.0	64.0	(2 0)	353.8
1997	28.1	71.6	6.8	126.0	64.0	14.0	310.5	6.2	46.7	2.9	5.0	(16.0)	44.8	34.3	118.3	9.7	131.0	64.0	(2.0)	355.3
1998	25.7	70.7	6.9	139.0	64.0	14.0	320.3	5.5	45.3	2.7	5.0	(16.0)	42.5	31.2	116.0	9.6	144.0	64.0	(2.0)	362.8
1999	23.6	69.2	6.6	150.0	64.0	14.0	327.4	4.8	43.8	2.6	5.0	(16.0)	40.2	28.4	113.0	9.2	155.0	64.0	(2.0)	367.6
2000	21.7	67.3	6.5	158.0	64.0	14.0	331.5	4.3	42.1	2.4	5.0	(16.0)	37.8	26.0	109.4	8.9	163.0	64.0	(2.0)	369.3

10-30 to 10-33 show the productive capacity of the various supply cases in a graphical form. These graphical presentations illustrate the relative importance of the various supply components in the different cases.

All cases show that the short term supply outlook for domestic crude oil is dominated by the decline in supply from established reserves. Only in the high case are future reserves additions sufficient to temporarily offset this decline. The low and base cases illustrate that Canada will face diminished domestic supplies of crude oil. The high case illustrates the effect of a high rate of new discoveries, rapid development of EOR and oil sands, and significant exploration successes in both the East Coast offshore and Beaufort Sea areas. However, even under the most favourable economic climate all of these developments are unlikely to occur together. A comparison of the total supply for the various cases is provided in Figure 10-34.

The Board believes that the modified base case, which stresses the importance of continued development of the oil sands and aggressive exploration in the frontier, is attainable.

Tables 10-14 to 10-17 show the supply of light and heavy crude oil separately. Such forecasts of supply by grade of oil are important because domestic disposal of heavy crude oil can be hampered by refinery capability to process the heavier crude oils. Upgrading of heavy crude oil would improve the supply-demand balance of light and heavy crudes and reduce demands on a declining supply of pentanes plus which is used as a diluent to improve the flow characteristics of heavy crude oil. However, upgrading slightly diminishes the overall supply as there is an upgrading loss of about ten percent. The Board has included at least one heavy crude oil upgrading facility in all but the low case. In the base case, heavy crude oil supplies are only marginally sufficient for such a facility, and the Board has some doubts whether this facility will be constructed and operating in 1988.

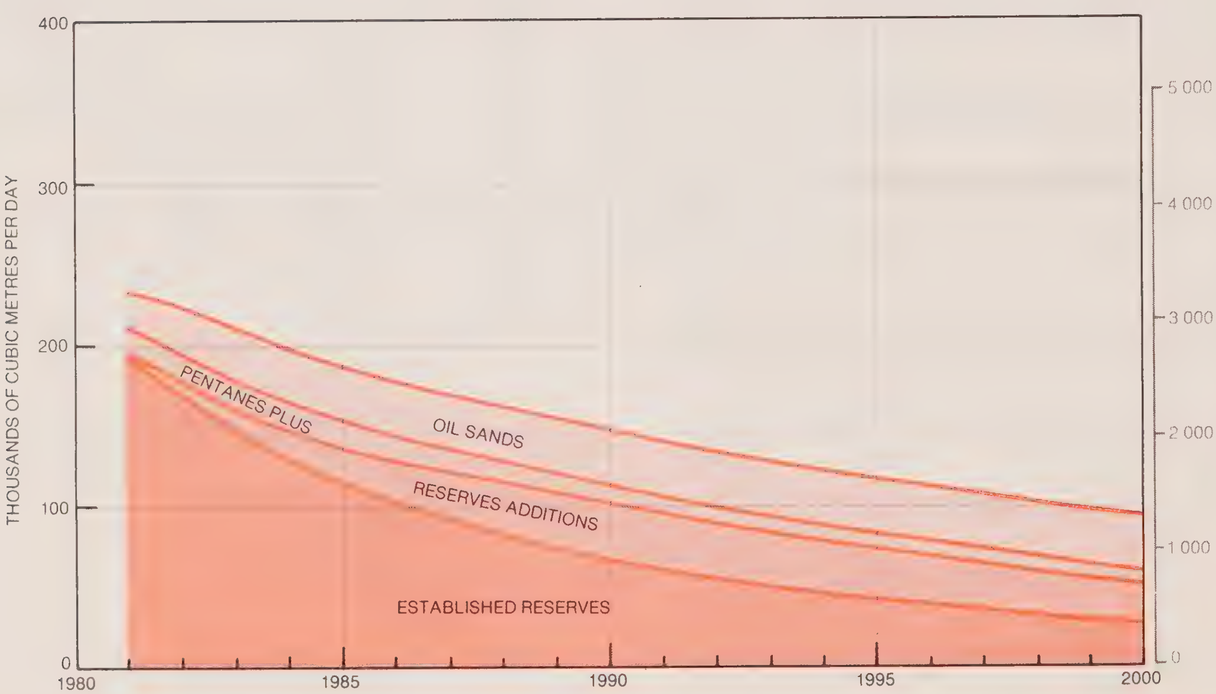

Figure 10-30 Productive Capacity of Crude Oil and Equivalent
NEB Low Case Forecast

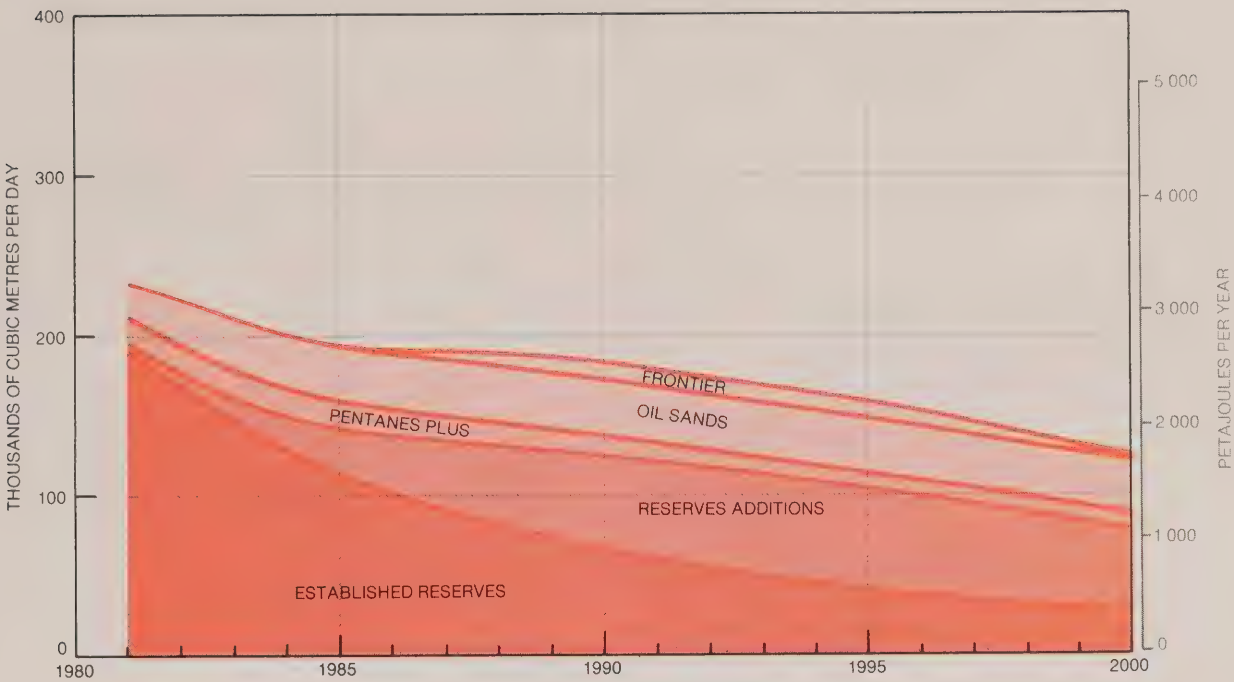

Figure 10-31 Productive Capacity of Crude Oil and Equivalent
NEB Base Case Forecast

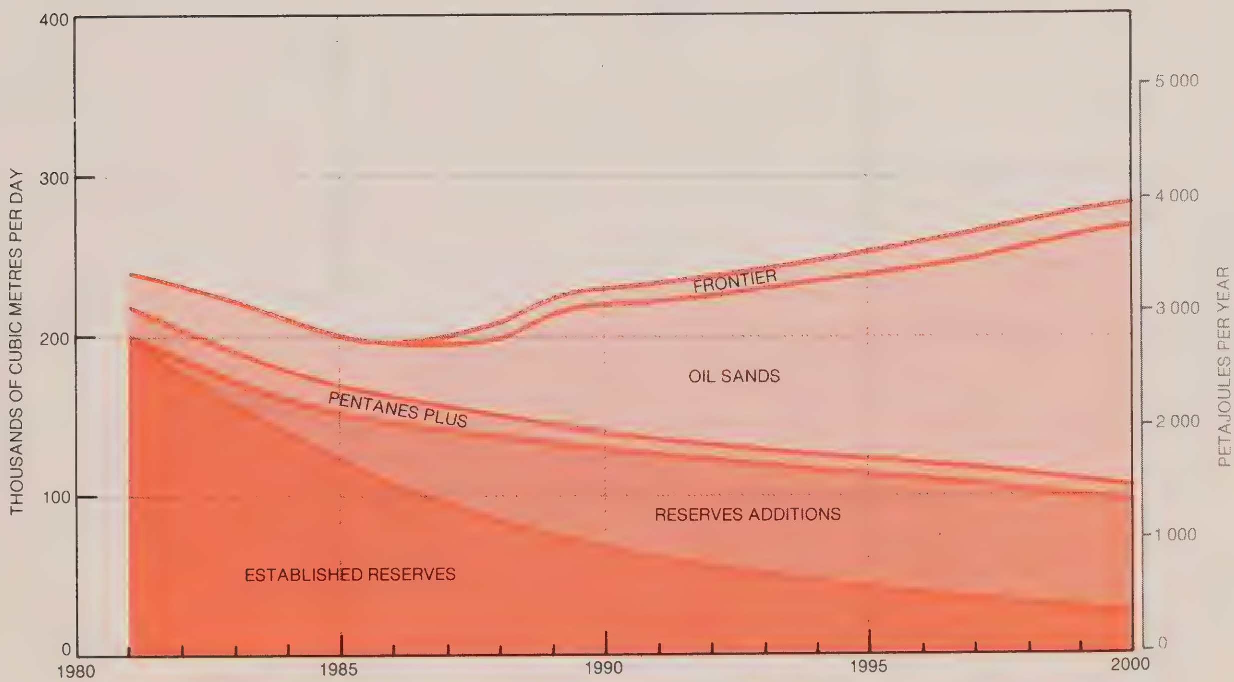

Figure 10-32 Productive Capacity of Crude Oil and Equivalent
NEB Modified Base Case Forecast

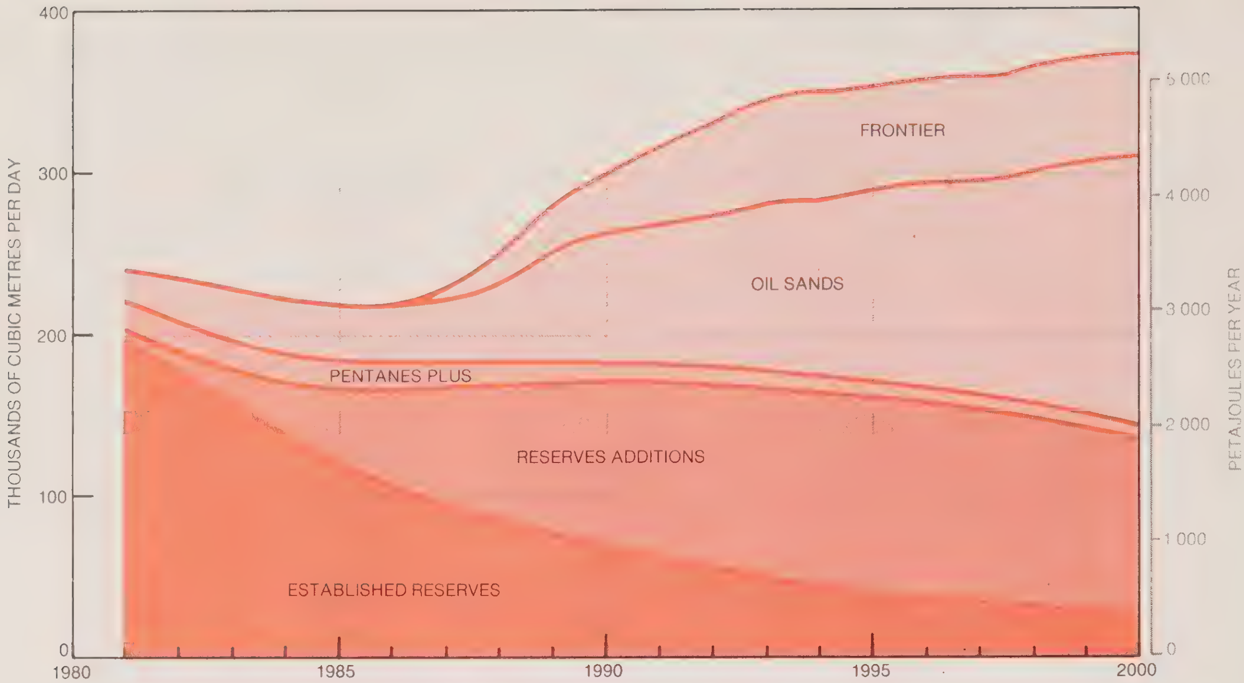

Figure 10-33 Productive Capacity of Crude Oil and Equivalent
NEB High Case Forecast

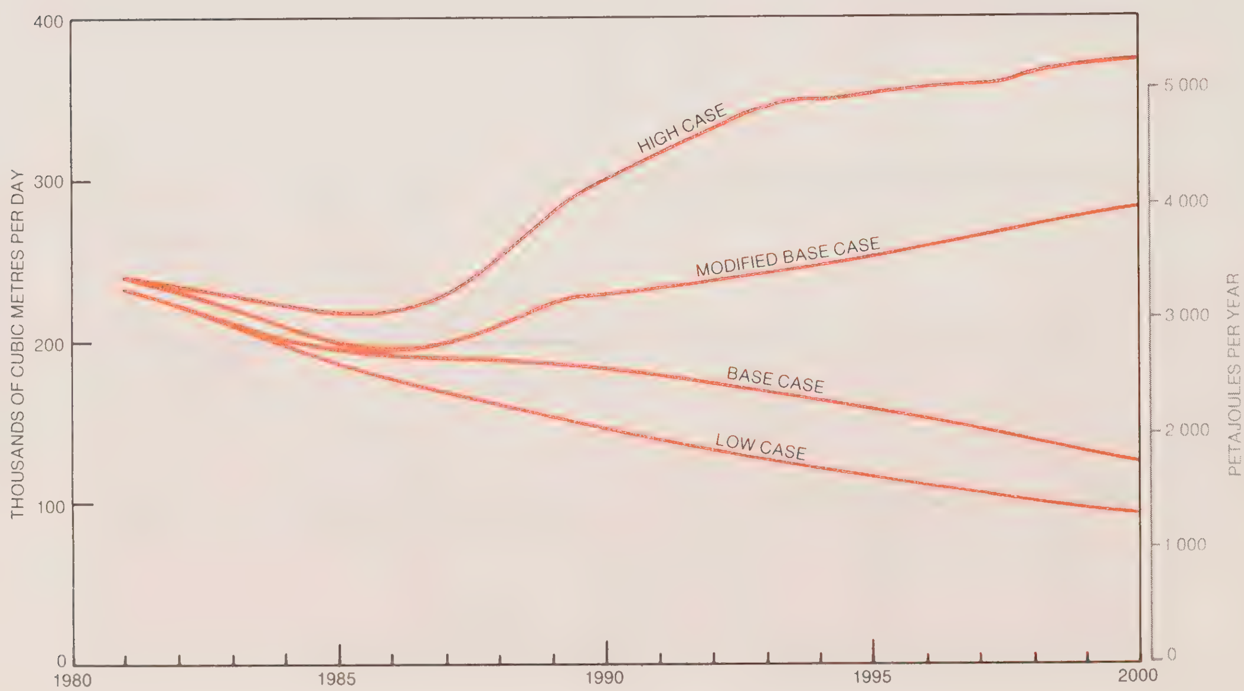

Figure 10-34 Productive Capacity of Crude Oil and Equivalent
Comparison of NEB Forecasts

CHAPTER 11
NATURAL GAS SUPPLY

11.1 Introduction

This chapter discusses the supply of Canadian natural gas from both conventional and other sources.

The subject matter of the chapter is organized as follows:
- —supply from conventional areas which includes established reserves as well as reserves additions and ultimate potential.
- —frontier areas.
- —very low permeability reservoirs.

An often stated view that Canada has an essentially inexhaustible supply of natural gas to meet its needs for as long in the future as one chooses to look is of some concern to the Board. As with oil supply, the forecasting of natural gas supply is fraught with uncertainties. The achievement of forecast levels of reserves additions is clearly dependent upon the drilling activity, which is in turn dependent upon economic and other factors, not the least of which is the degree of success in finding new gas. Canada's frontier areas are in the early stages of development and, while results to date are highly encouraging, currently established reserves are only approximately one-quarter of remaining established reserves of the conventional areas. Very low permeability reservoirs may prove an important source of natural gas in future, but technology to produce these reservoirs has not been demonstrated and the quantity of gas available for exploitation is not known with any degree of accuracy.

To assist the Board in its ongoing assessment of gas supply, it was requested in the Outline for Submissions to this inquiry that Submittors provide detailed basic data, reservoir studies and deliverability forecasts for some 150 pools selected by the Board. These were pools where the operator's estimate of reserves differed substantially from those published by regulatory agencies, and pools where it was felt the Board might lack current information. Data forms were provided for both reserves and deliverability in order to facilitate Submittors' responses and, in some cases, the Board made its actual performance plots available for comment by the operator. Responses were received for approximately two-thirds of the identified pools.

To underline the many uncertainties surrounding future natural gas supply, the Board has prepared high and low cases as well as a base case for its forecasts of reserves additions and its estimates of ultimate potential for the conventional areas. While the Board has for some time recognized established reserves in the frontier areas, only illustrative deliverability forecasts are made because of the questions associated with the timing of initial deliveries and volumes of production.

11.2 Supply From Conventional Areas

11.2.1 *Established Reserves*

Views of Submittors

Estimates of remaining established reserves of marketable gas for all of the conventional areas were received from Ontario, CPA, IPAC, Consolidated, Dome, Gulf, Imperial, Norcen, Petro-Canada, ProGas, and TCPL. NOVA submitted an estimate for Western Canada only; estimates for the respective provinces were submitted by British Columbia and Saskatchewan. Westcoast submitted estimates for its own supply area. SPC submitted estimates for currently connected reserves in its own supply area.

Submittors' estimates are compared in Table 11-1. The majority of these estimates were based upon those of provincial regulatory agencies, NEB, and CPA. AERCB did not submit an estimate but an estimate, as given in AERCB report 80-18, is included in the table for comparative purposes. Saskatchewan pointed out that its estimate was 6.3 billion cubic metres (0.2 exajoules) less than the estimate of remaining recoverable reserves published in the province's annual reserves report. This is to account for fuel and losses associated with field gathering operations and plant processing.

All the submitted estimates except that of TCPL were as of 31 December 1979. TCPL's estimate was as of 31 December 1980.

TCPL and NOVA submitted the highest estimates. The view of both these companies was that the reserves of certain fields were understated by the regulatory agencies.

The major producing companies and many independent operators submitted reserves estimates for the pools listed in the hearing order. In addition some companies submitted estimates for other pools and fields which they operated or in which they had a substantial interest.

There were few comments with respect to the effect of the NEP on established reserves. Ontario stated that no changes of note were anticipated for current reserves as a result of the NEP. TCPL indicated that any reduction in established gas reserves as a result of the NEP would be fairly minimal.

Views of the Board

The Board's estimate of the remaining established reserves of marketable gas in the conventional areas is 76.2 exajoules as of 31 December 1980. Individual pool estimates, which together make up this total, are available for examination by interested parties at the Board's Geology and Reserves Office in Calgary. The Board has included in established reserves only gas from conventional reservoirs. A regional breakdown of the Board's estimate of remaining established reserves is given in Table 11-1. Also shown for comparative purposes are the Board's

Table 11-1

REMAINING ESTABLISHED RESERVES OF MARKETABLE NATURAL GAS
CONVENTIONAL AREAS
(31 December 1979)
(Exajoules)

	B.C.	Alta.	Sask.	Southern Territories	Eastern Canada	Canada Total
AERCB	—	66.7[1]	—	—	—	—
Saskatchewan	—	—	1.1	—	—	—
B.C.	8.3	—	—	—	—	—
Ontario	8.3	66.7	1.3	0.5	0.3	77.1
CPA	8.1	64.0	1.4	0.6	0.3	74.4
IPAC	8.2	66.7	1.4	0.3	0.3	76.9
Consolidated	7.2	68.1	1.5	0.3	0.3	77.4
Dome	8.2	66.7	1.4	0.3	0.3	76.9
Gulf	8.1	64.0	1.4	0.6	0.3	74.4
Imperial	7.6	66.5	1.6	0.5	0.2	76.4
Norcen	8.2	67.1	1.4	0.3	0.3	77.3
NOVA	8.2	72.9	1.4	0.4	—	82.9
Petro-Canada	8.2	66.6	1.4	0.3	0.3	76.8
ProGas	8.2	66.7	1.3	0.3	0.3	76.8
TCPL[2]	8.7	69.3	1.4	0.3	0.3	83.0[3]
Westcoast	8.4	—	—	0.3	—	—
NEB	8.1	65.7	1.4	0.3	0.3	75.8
NEB at 31 Dec. 1980 (preliminary)	8.3	66.2	1.1	0.3	0.3	76.2

Notes to Table 11-1
Gross heating values used in conversion, as required, to energy units:

British Columbia	38.8 MJ/m^3
Alberta	38.8 MJ/m^3
Saskatchewan	36.5 MJ/m^3
Southern Territories	36.6 MJ/m^3

(1) From AERCB Report 80-18
(2) As of 31 December 1980.
(3) Total includes an additional 3 EJ, an amount by which TCPL believed that the regulatory agencies had underestimated TCPL's contracted reserves.

estimates as of 31 December, 1979. The Board does not believe any changes to its estimate of established reserves are required as a result of the NEP.

The Board estimates that 4.8 exajoules of marketable gas reserves were added in the conventional areas during 1980, before considering production of 2.7 exajoules and negative revisions to initial established reserves of 1.7 exajoules. The resulting net increase in remaining established reserves is 0.4 exajoules. The negative revisions involve 1.4 exajoules in Alberta, reflecting pool re-evaluations and 0.3 exajoules in Saskatchewan to correct for field and plant losses not reported in the annual reserves publications of the Saskatchewan Department of Mineral Resources.

Appendix O lists the pools where major negative revisions were made in 1980, and shows the Board's reserves estimates at 31 December 1980. The estimates were determined by production performance evaluation and geological studies carried out during the past year. In some cases these estimates were confirmed by studies conducted by the operating companies and submitted to AERCB for purposes of that agency's semi-annual gas reservoir reviews. The poor production performance of some pools is of concern to the Board and continued emphasis will be placed on this aspect of reservoir evaluation in the future. The Board anticipates that additional negative revisions due to poor production performance will have to be made.

The Board's estimates of reserves for pools listed in the hearing order are given in Appendix P. These estimates are based on evidence submitted and on individual pool studies carried out by the Board. In this regard it should be noted that the Board considers reserves estimation and re-evaluation to be an ongoing process. It will consider pertinent new information at any time and make revisions to its estimates as indicated by such information.

11.2.2 *Reserves Additions and Ultimate Potential*

Views of Submittors

Forecasts of reserves additions for all or portions of the conventional areas, prepared prior to the announcement of the NEP, were provided by 16 Submittors. Gulf and TCPL submitted revised additions forecasts following the announcement of the NEP. Other Submittors provided assessments of the impact of the NEP in more general terms. Thirteen assessments of ultimate potential for all or portions of the conventional areas were submitted.

Several Submittors addressed the question of the effect of economic factors on gas reserves additions. Their primary concern was with the lack of markets relative to the capable supply of gas, which was felt to have an adverse effect on drilling activity, and thereby on reserves additions. The proposed domestic market expansion outlined in the NEP was considered to be helpful, provided that producers would not have to share the cost of servicing the new markets. However, these new markets were considered to be too small to have much impact on the current levels of shut-in gas. It was felt that the new markets would result in little, if any, increase in drilling activity.

The most common method used by Submittors in assessing the effects of various economic conditions, such as onstream delays, on the financial viability of a project was discounted cash flow analysis. By using this method the present value of a project, and its rate of return, were obtained under various economic conditions. Expectations of future gas prices, costs and market availability were important factors with this method. Thus the effect of the NEP on drilling activity and reserves additions would depend on pre-NEP expectations concerning prices and markets relative to prices and markets outlined in the NEP. In this respect, some Submittors found the price increase outlined in the NEP after 1983 to be an improvement, while some did not.

The Gas Bank proposal outlined in the NEP was received with reservations by most Submittors. While many thought that it might help small firms with cash flow problems it was viewed as too small to alleviate the adverse effects of the alleged surplus of shut-in gas. Many of the Submittors felt that the Gas Bank would be difficult to implement and administer.

The submitted forecasts of total reserves additions to the year 2000 are compared in Table 11-2 and annual additions over the forecast period from 1980 to 2000, pre-NEP and post NEP

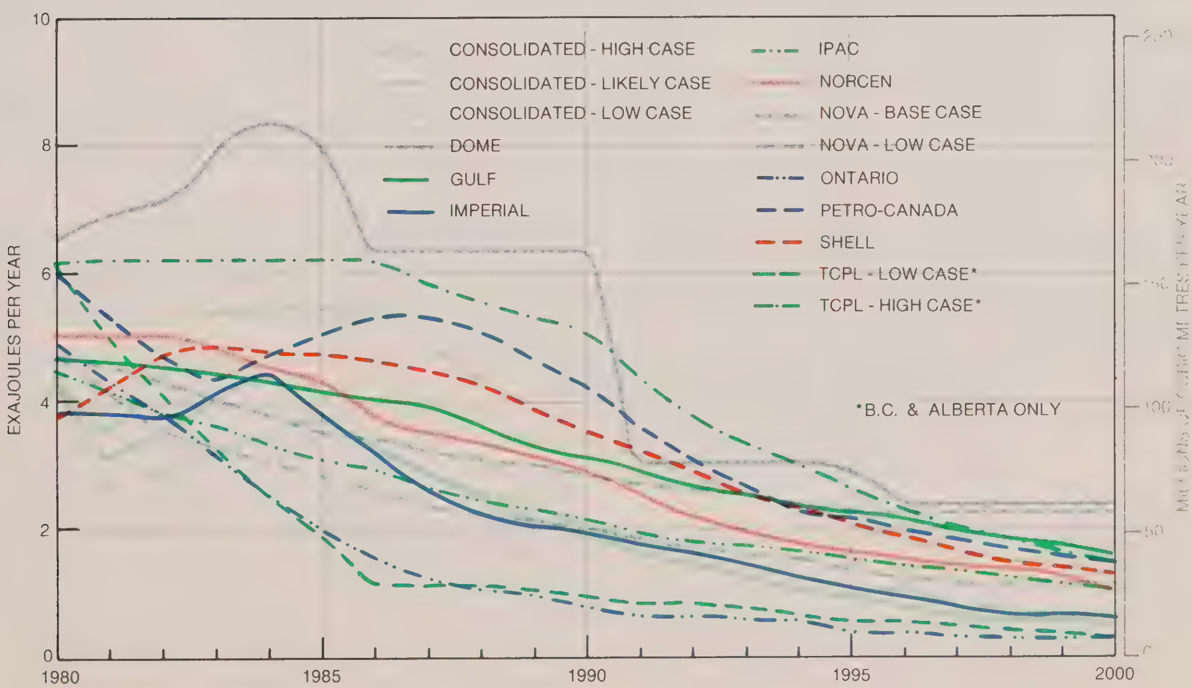

Figure 11-1 Marketable Natural Gas Reserves Additions
Comparison of Forecasts: Pre-NEP

Table 11-2

MARKETABLE NATURAL GAS RESERVES ADDITIONS FORECASTS CONVENTIONAL AREAS 1980-2000 (Exajoules)

	B.C.	Alta.	Sask.	Southern Territories	Eastern Canada	Total
AERCB(1)	—	39.1	—	—	—	—
Saskatchewan	—	—	1.5	—	—	—
B.C. (base)	6.9	—	—	—	—	—
B.C. (optimistic)	8.9	—	—	—	—	—
B.C. (pessimistic)	4.3	—	—	—	—	—
Ontario	5.9	25.2	0.5	(2)	—	31.6
CPA	16.3	52.3	1.1	1.1	0.1	70.8
IPAC	—	—	—	—	—	51.2
Consolidated most likely	—	—	—	—	—	46.7
Consolidated (high)	—	—	—	—	—	72.7
Consolidated (low)	—	—	—	—	—	46.0
Dome	17.0	84.8	0.8	2.0	—	104.7
Gulf	12.8	54.1	0.6	—	0.5	68.0
Gulf (NEP)	8.6	36.2	0.4	—	0.3	45.5
Imperial	8.0	38.8	0.4	0.7	—	47.8
Norcen	—	—	—	—	—	63.1
NOVA (base)	6.1	58.5	1.1	—	—	65.7
NOVA (low)	4.9	42.2	1.1	—	—	48.2
Petro-Canada (pre-NEP)	10.0	67.2	0.8	—	—	78.0
Petro-Canada (post-NEP)	—	—	—	—	—	75.9
ProGas	—	—	—	—	—	46.0
Shell	18.7	49.7	1.0	—	—	69.4
TCPL (low)	4.8	30.7	—	—	—	35.5
TCPL (high)	16.4	77.0	—	—	—	93.4
TCPL (NEP)	7.4	53.6	—	—	—	61.0
TCPL (modified NEP)	9.0	65.6	—	—	—	74.6
WTCL(3)	7.3	—	—	—	—	—
NEB (base)	5.5	34.6	0.5	(2)	—	40.6
NEB (low)	4.4	28.9	0.5	(2)	—	33.8
NEB (high)	9.3	53.4	0.5	(2)	—	63.2

NEB estimates reflect negative adjustments in 1980 to established reserves for pool performance in Alberta and field and plant fuel and losses in Saskatchewan.

Gross heating values used in conversion, as required, to energy units:

British Columbia	37.5 MJ/m^3
Alberta	37.5 "
Saskatchewan	36.5 "
Southern Territories	36.5 "

(1) From AERCB Report 80-18
(2) Southern Territories included in British Columbia total
(3) For the period 1980-1999

Table 11-3

ULTIMATE POTENTIAL ESTIMATES OF MARKETABLE NATURAL GAS CONVENTIONAL AREAS (Exajoules)

	B.C.	Alta.	Sask.	Southern Territories	Eastern Canada	Total
AERCB[1]	—	137-148	—	—	—	—
Saskatchewan	—	—	3	—	—	—
B.C.	27	—	—	—	—	—
CPA	41	165	4	2	1	213
IPAC	—	—	—	—	—	190+[2]
Consolidated	—	—	—	—	—	170
Consolidated (high)	—	—	—	—	—	200
Dome	34	168	7	4	1	214
Gulf	31	169	3	—	2	205
Imperial	26	152	3	2	1	184
NOVA	25	181	12	—	—	218
Petro-Canada	33	170	3	2	1	209
Shell	40	157	3	—	—	200
TCPL	34	141-187	3	2	1	181-227
Westcoast	26	—	—	—	—	—
NEB (base)	21	145	3	[3]	1	170
NEB (low)	19	135	3	[3]	1	158
NEB (high)	26	165	3	[3]	1	195

Gross heating values used in conversion, as required, to energy units:

British Columbia	38.5 MJ/m^3
Alberta	38.5 "
Saskatchewan	36.5 "
Southern Territories	36.5 "

[1] From AERCB Report 80-18; AERCB estimated that with higher gas prices than currently anticipated and substantial technological breakthrough, the ultimate potential of Alberta could exceed 211 EJ.
[2] IPAC's estimate of ultimate potential was stated to be in excess of 190 EJ.
[3] Southern Territories included in British Columbia total.

respectively, are illustrated in Figures 11-1 and 11-2. Estimates of ultimate potential are compared in Table 11-3. AERCB estimates taken from its Report 80-18 have been included in the tables for comparative purposes.

British Columbia submitted reserves additions forecasts and an ultimate potential estimate for the Northeastern portion of the province. Three additions forecasts were submitted, a base case, an optimistic case and a pessimistic case, each assuming a different level of drilling activity. In the base case British Columbia estimated that 183 billion cubic metres (6.9 exajoules) of marketable gas would be added to the year 2000. In the optimistic case it estimated 237 billion cubic metres (8.9 exajoules) would be added and in the pessimistic case 115 billion cubic metres (4.3 exajoules). The ultimate potential was estimated to be 709 billion cubic metres (27 exajoules) of marketable gas.

Saskatchewan estimated the ultimate potential of the province to be 40 billion cubic metres (1.5 exajoules) in addition to the initial established reserves of 57.4 billion cubic metres (2.1 exajoules). A majority of these additional reserves was attributed to the shallow Milk River and Second White Specks formations in the Western portion of the province. Saskatchewan forecast that all the 40 billion cubic metres would become established reserves within the forecast period.

Ontario estimated the reserves additions for the conventional areas during the period 1980 to 2000 to be some 850 billion cubic metres (32 exajoules). This estimate was based upon the assumption that activity levels would be maintained at, or near, current levels in the near to medium term.

In a supplementary report, Ontario stated that it believed the NEP would cause a considerable slowdown in activity. This would lead to a reduction in reserves additions for Alberta of some 20 percent below that forecast in the early years, but additional quantities would probably be found later. In the case of British Columbia it stated that the NEP, along with the slowdown due to a depressed export market, would likely significantly reduce reserves additions. It concluded that recent events had made it difficult to see how any short-term predic-

tions, much less long-term, could be attempted with any reasonable degree of confidence.

CPA provided estimates of reserves appreciation, future discoveries, and ultimate potential for the conventional areas. The additions for all the conventional areas to the year 2000 were estimated to total 70.8 exajoules. The ultimate potential of these areas was estimated to be 213 exajoules. These estimates were based on comprehensive studies for Alberta and British Columbia.

CPA stated that it believed that the impact of the NEP would be to reduce new discoveries by one-third.

IPAC stated that its estimate of the ultimate potential of Western Canada was unchanged from the 190 exajoules submitted to the 1978 hearing on natural gas supply and demand. The Association estimated additions for Southern Canada to total 51.2 exajoules for the forecast period, based on the assumption of adequate markets. It noted that reserves additions were difficult to forecast with confidence because these would depend on ultimate reserves, and exploration and development activity. Activity would be determined by markets and economics, which in turn would depend upon the conditions and prices imposed on exports. IPAC stressed the need for new markets in order to stimulate industry activity. Increasing the domestic markets for gas was thought to be insufficient.

IPAC could not be specific as to the impact of the NEP on reserves additions but stated that the effect would undoubtedly be that less gas would be developed than otherwise.

Consolidated submitted gas reserves additions forecasts for three cases, each based on different levels of future export. The ultimate potential of the conventional areas was assumed to be 170 exajoules for the low and most likely cases, and 200 exajoules for the high case. Total reserves additions for the conventional areas to the year 2000 were estimated to be 46.0 exajoules in the low case, 46.7 exajoules in the most likely case and 72.7 exajoules in the high case.

With regard to the impact of the NEP, the company stated that, at best, the implementation of all the measures outlined in the NEP would defer reserves additions for a number of years and, at worst, would cause a substantial overall decrease in Canada's ultimate recoverable reserves. In view of the NEP it considered the low case as the most realistic forecast. It concluded that if the NEP were left in place without modification,

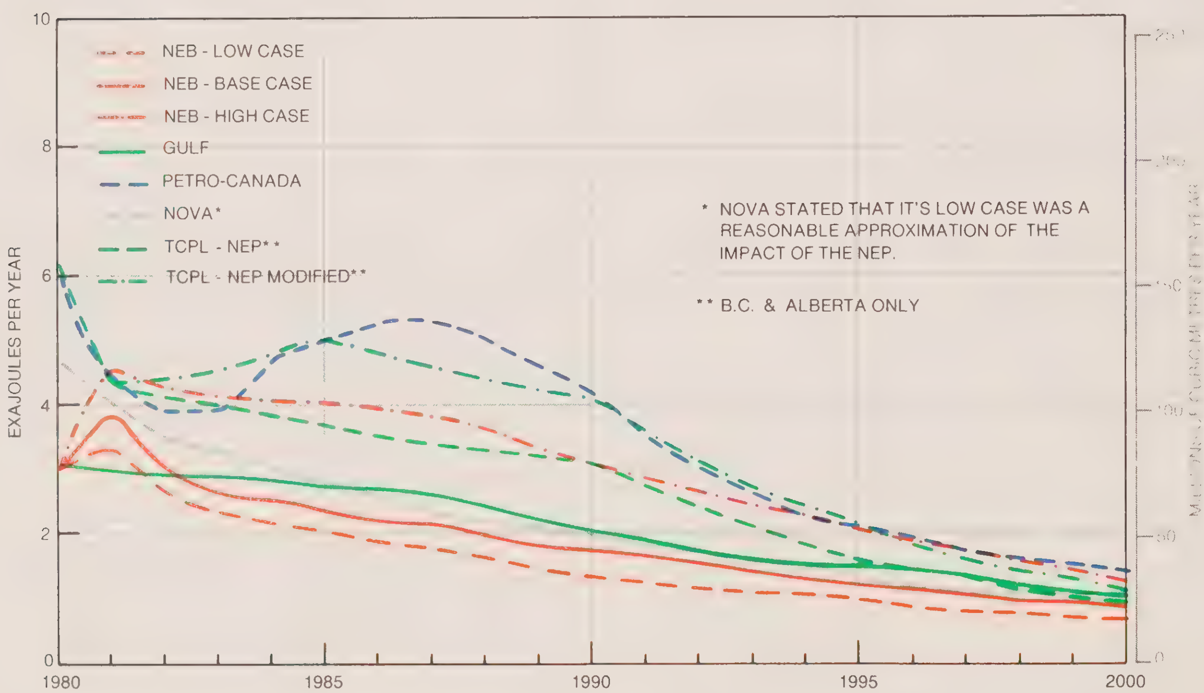

Figure 11-2 Marketable Natural Gas Reserves Additions
Comparison of Forecasts: Post-NEP

the probable result would be reserves additions with a profile that would be 10 to 20 percent less than forecast in the most likely case.

Dome estimated the ultimate potential of the conventional areas to be 214 exajoules, 15 exajoules higher than the estimate it submitted to the Board in 1978. Its reserves additions forecast, which assumed favourable market and economic conditions, was 104.7 exajoules over the forecast period.

Gulf estimated the ultimate potential of the conventional areas to be 5.34 trillion cubic metres (205 exajoules). It noted that natural gas reserves additions in the past two years had been much greater than anticipated, leading to upward revisions in the estimated ultimate potential. The company provided a reserves additions forecast to the year 2000 which totalled 1 814 billion cubic metres (67.9 exajoules) for the conventional areas.

Following the announcement of the NEP Gulf provided a revised forecast with total additions of 1 215 billion cubic metres (45.5 exajoules). It made no changes in the ultimate potential of the conventional areas as a result of the NEP.

Imperial estimated the ultimate potential of the conventional areas to be 184 exajoules, using a geological-statistical methodology. It noted that it had increased its estimate by 350 billion cubic metres (13 exajoules) over that given in its 1979 submission and attributed this increase to the Elmworth area and Lower Cretaceous reservoirs in Alberta. The company provided a reserves additions forecast which totalled 47.8 exajoules for the conventional areas over the forecast period. It noted that reserves additions in 1979 were higher than expected.

Imperial stated that as a result of the NEP it expected lower forecasts of supply from reserves additions, since the NEP would reduce the number of economically attractive exploration and development projects.

Norcen provided a forecast of gas reserves additions for Western Canada which totalled 1 682 billion cubic metres (63.1 exajoules) to the year 2000. This forecast was based on a projection of the declining reserves found per metre of exploratory drilling and on an assumed profile of exploratory drilling during the forecast period.

With regard to the NEP, Norcen stated that new discoveries and appreciation from new discoveries would be lower in the 1980s and higher in the 1990s than in its original pre-NEP forecast.

NOVA stated that it believed Canada's reserves of natural gas would grow significantly in the future. As a result it foresaw no deficiency of natural gas over the forecast period. The company adopted the ultimate potential estimates of a consultant, for its submission. These estimates totalled 218 exajoules for the Western Canada Sedimentary Basin. A base case and a low case forecast of reserves additions were made with additions of 65.7 exajoules and 48.2 exajoules, respectively. NOVA found that forecasts of reserves additions were sensitive to economic factors, principally market lead time, netbacks and costs.

NOVA stated that its preliminary studies indicated that the NEP would result in a decline in the anticipated discovery rate for gas by one-third each year for the next ten years and that its low case was a reasonable approximation of the impact of the NEP.

NOVA made reference to the carrying cost of shut-in gas, which, it estimated was from $1.06 to $4.25 per thousand cubic metres annually. One method used to calculate the cost was to compare the present value of marketing gas today to that of marketing it at a later date. The difference represented the foregone opportunity of selling that gas at an earlier date. Another method was to assess the financial cost incurred by expending funds in the present and having to wait for a period of time before being able to produce the reserves.

Petro-Canada estimated the ultimate potential of the conventional areas to be 209 exajoules, with reserves additions over the forecast period of 78.0 exajoules. It noted that in both British Columbia and Alberta it had become obvious that at this time the ultimate potential is not a constraining factor on reserves additions and that reserves additions over the last several years have primarily reflected the level of industry activity. It stated that there was an impending downturn in industry activity, the immediate cause of which was the lack of markets relative to the currently proven gas supply. By the mid-1980s a reversal in this situation was expected with a return to current exploration levels.

After the announcement of the NEP, Petro-Canada revised its earlier forecast of reserves additions in the short run from a 30 percent downturn reflecting market constraints to a 40 percent downturn, with recovery in the mid-1980s driven by market improvements and NEP proposed higher prices after 1983. It concluded that no revisions were necessary to its long-term gas supply forecast as a result of the NEP.

ProGas estimated that total reserves additions to the year 2000 for the conventional areas would be 46.0 exajoules. It concluded that unless additional markets were obtained both in Canada and in the United States within the next few years, exploratory drilling activity would decline and this would result in a decline in the rate of new discoveries.

Shell used recent studies undertaken by the CPA, in which it participated, as the basis for its estimates of ultimate potential for Alberta and British Columbia. For Saskatchewan it updated a forecast of the Saskatchewan Department of Mineral Resources. On these bases the undiscovered natural gas potential of Western Canada was estimated to be 2 332 billion cubic metres (90 exajoules). Shell estimated total reserves additions to the year 2000 for Western Canada to be 69.4 exajoules.

Following the announcement of the NEP, Shell reduced the new discoveries portion of its natural gas supply forecast, to reflect decreased exploratory activity. It estimated that deliverability from new discoveries would fall to 60 percent of the previous estimate by 1987, and warned that this should be considered as more than a delay in deliverability because of the loss of hardware and skilled staff.

TCPL stated that it considered the Alberta ultimate reserves to be in the range of 141 to 187 exajoules. This assessment was based on its own studies and those of a consultant. The consult-

ant estimated the ultimate potential of Alberta to be 172 exajoules with a range of 163 to 184 exajoules. This represented an increase of 24 exajoules over its previous estimate. TCPL estimated the ultimate potential of British Columbia to be 34 exajoules and the total ultimate potential of the conventional areas to be in the range of 181 to 227 exajoules. TCPL stated that economic factors, either directly or indirectly, were the most significant determinants of the rate of reserves additions. The primary economic factor which would constrain industry activity over the next five years was considered to be the lack of markets. The company provided a high and a low case forecast of reserves additions for Alberta and British Columbia, reflecting different activity levels. In the high case, forecast additions totalled 93.4 exajoules over the forecast period for Alberta and British Columbia. In the low case the total was 35.5 exajoules.

As a result of the NEP, the company was unable to present a single most likely case and instead provided two projections of reserves additions. The first case was based on the assumption that drilling activity would decrease by some 25 percent and would remain at that level for some 10 years before declining further at a rate of 10 percent per year. The second case was based on the assumption that after a decline in 1981, a combination of additional export market opportunities and/or amendments to the NEP would return drilling activity to the 1980 level over a four-year period. In the first case the additions over the forecast period for Alberta and British Columbia were estimated to total 61.0 exajoules and in the second case 74.6 exajoules.

The forecast of reserves additions and the ultimate potential estimate submitted by WTCL were unchanged from those submitted to the 1978 Natural Gas Supply and Requirements hearing. The company used the historical growth of proved initial pipeline gas during the period 1968 to 1977 to estimate annual reserves additions for British Columbia. The growth trend was determined by the least squares method from which the company concluded that the historical annual growth rate for British Columbia was approximately 13.9 billion cubic metres (0.52 exajoules). It assumed this rate would continue until 1982 after which it would decline at five percent per year. WTCL estimated that 195 billion cubic metres (7.3 exajoules) would be added over the twenty-year period from 1980 to 1999. The company indicated that a continuation of this trend would give an ultimate potential of approximately 663 billion cubic metres (25.5 exajoules). It further stated that it believed the ultimate potential of the province to be in the order of 570 to 850 billion cubic metres (22 to 33 exajoules) because of the favourable geology of certain regions in the province.

Views of the Board

The Board recognizes that reserves additions forecasts are largely subjective judgements based on perceptions of future drilling activity, market opportunities, economic conditions and ultimate potential. It expects divergent views on these matters and is appreciative of all the opinions expressed in the submissions.

Submittors were generally of the view that reserves additions for the non-frontier areas were primarily determined by drilling activity but were constrained by the ultimate potential in the longer term. The Board, in previous reports, has indicated that it is in general agreement with this view.

To illustrate the relationship between annual reserves additions and drilling activity, a table listing annual drilling statistics for Alberta was included in the Board's 1979 Gas Report. The same statistics with data added up to the end of 1980 are listed in Table 11-4. Also listed are the Board's annual reserves additions for Alberta. The table shows that the higher additions rates of the late 1970s were associated with increased drilling effort.

In its 1979 Gas Report, the Board, for its expected case, forecast reserves additions in the conventional areas for the period 1978 to 2000 to be 40.1 exajoules, with low and high cases of 30.6 exajoules and 49.6 exajoules respectively. In its November 1979 Reasons for Decision, the expected case estimate was increased to 48.4 exajoules to reflect an increase in the expected ultimate potential of the conventional areas. In both the February 1979 Gas Report and November 1979 Reasons for Decision, it was forecast that annual reserves additions would start to decline after 1980 due to constraints upon drilling activity growth.

The Board, having considered the evidence submitted concerning market conditions, ultimate potential and the economic impact of the NEP, finds that revisions to its forecast of reserves additions are warranted. For its base case the Board now fore-

Table 11-4

DRILLING STATISTICS(1)
AND
NEB ESTIMATES OF ADDITIONS TO INITIAL ESTABLISHED RESERVES
OF MARKETABLE NATURAL GAS
ALBERTA

Year	Drilling Metreage (Mm) Exploratory	Development(2)	Total	Annual Additions (EJ)
1968	1.49	0.64	2.13	2.11
1969	1.46	0.69	2.15	4.64
1970	1.35	0.67	2.02	2.11
1971	1.31	0.76	2.07	4.53
1972	1.56	0.83	2.39	0.11
1973	1.81	1.30	3.11	6.22
1974	1.57	1.28	2.85	1.58
1975	1.45	1.43	2.88	2.43
1976	1.95	2.25	4.20	4.39
1977	2.31	2.18	4.49	5.89
1978	2.79	2.25	5.04	7.01
1979	3.25	2.19	5.44	4.13
1980(3)	4.00	2.50	6.50	2.80(4)

(1) data from CPA Statistical Year Books
(2) excluding oil development metreage
(3) drilling metreage for 1980 has been estimated
(4) subject to final adjustments

casts that 40.6 exajoules of reserves will be added in the conventional areas during the period 1980 to 2000, a decrease of 3.1 exajoules from the forecast for this period in the November 1979 Reasons for Decision. Also, annual additions are forecast to be smaller in the earlier years but larger in the later years than in the previous forecast. The Board assumes in the base case that drilling activity will decrease by approximately 25 percent in 1981 plus an additional 10 percent in 1982 from the 1980 level and by an additional 5 percent in 1983. The Board further assumes that the drilling activity will remain constant at the 1983 level for the remainder of the forecast period, a level comparable to that experienced in 1976. The Board's base case forecast is presented in Table 11-5 and compared with Submittors' forecasts in Figure 11-2. Low and high cases of 33.8 exajoules and 63.2 exajoules reflecting the Board's range of ultimate potential, are also depicted in Figure 11-2. Drilling activity for the low case is assumed to be the same as for the base case; for the high case it is assumed to be 25 percent lower than the 1980 level in 1981 and 1982, returning gradually thereafter to the 1980 level.

Table 11-5

NEB BASE CASE FORECAST OF MARKETABLE NATURAL GAS RESERVES ADDITIONS CONVENTIONAL AREAS 1980-2000 (Exajoules)

YEAR	British Columbia	Alberta	Saskatchewan	Total
1980 (actual)[1]	0.53	2.80	(0.21)	3.12
1981	0.50	3.37	0.02	3.89
1982	0.41	2.71	0.02	3.14
1983	0.36	2.36	0.02	2.74
1984	0.34	2.21	0.02	2.57
1985	0.32	2.07	0.06	2.45
1986	0.30	1.93	0.06	2.29
1987	0.28	1.81	0.06	2.15
1988	0.27	1.70	0.06	2.03
1989	0.25	1.59	0.06	1.90
1990	0.24	1.48	0.06	1.78
1991	0.22	1.39	0.06	1.67
1992	0.21	1.30	0.06	1.57
1993	0.20	1.22	0.06	1.48
1994	0.19	1.14	0.06	1.39
1995	0.17	1.06	0.04	1.27
1996	0.16	1.00	0.02	1.18
1997	0.15	0.93	0.02	1.10
1998	0.14	0.88	—	1.02
1999	0.14	0.82	—	0.96
2000	0.13	0.76	—	0.89
Totals	5.51	34.53	0.55	40.59

[1] subject to final adjustments

Evidence concerning the ultimate potential of the conventional areas was specifically requested by the Board for its 1978 gas inquiry. Based on the evidence submitted and its own studies, the Board adopted a range of ultimate potential for the conventional areas of 134 exajoules to 165 exajoules with an expected value of 155 exajoules. Subsequently, as a result of evidence presented at the 1979 gas export applications hearing, the expected value was increased to 170 exajoules.

The Board notes that the submitted estimates of ultimate potential for the conventional areas were generally higher than previously submitted. It has considered the evidence in support of these upward adjustments but concludes that no upward revision to its own base case estimate is justified at this time. However, low and high case estimates of 158 exajoules and 195 exajoules respectively, are adopted by the Board for the purpose of developing low and high case reserves additions forecasts. The Board, in previous reports, has emphasized the judgemental nature of estimates of ultimate potential and it continues to believe that ultimate potential cannot be quantified with certainty either mathematically or by the application of geological concepts. It further notes that the potential for large additional reserves in low permeability reservoirs has added to the uncertainty.

11.2.3 *Deliverability*

Views of Submittors

Thirteen Submittors provided pre-NEP forecasts of deliverability from the conventional producing areas. These forecasts are summarized in Table 11-6 and in Figure 11-3. Other Submittors, while not providing a total Canada deliverability forecast, did provide aggregate forecasts for specific transportation systems or regions. A & S's estimate of deliverability was limited to reserves it had under contract. WTCL combined individual pool deliverability estimates for connected reserves with estimates of deliverability from unconnected and trend gas reserves in its supply area. SPC provided an estimate of deliverability from its owned and contracted reserves in Alberta and Saskatchewan. Saskatchewan's forecast of total deliverability for the province included SPC's estimate of deliverability from the province's proven reserves and its own estimate of deliverability from reserves additions. British Columbia, for its estimate of supply from B.C., combined individual deliverability forecasts for all major pools with aggregate forecasts for the remaining small pools, unconnected reserves and each of three reserves additions estimates.

Post-NEP gas deliverability forecasts from reserves in the conventional producing areas were provided by six Submittors. These forecasts are summarized in Table 11-7 and illustrated on Figures 11-4 to 11-10. Other Submittors, while not providing post-NEP forecasts of deliverability, commented on how the NEP would affect their own operations as well as those of the industry. Considerable concern was expressed over the greatly reduced capital that would be available for reinvestment by the industry as a result of decreased cash flow from the imposition of an eight percent Petroleum and Gas Revenue Tax and a 28

Table 11-6

NATURAL GAS DELIVERABILITY FROM CONVENTIONAL AREAS
Submittors' Pre-NEP Forecasts
(Petajoules/Year)

Year	CPA	Consoli-[2] dated	Dome	Gulf[1]	Imperial	Norcen[1]	NOVA	Ontario[3]	Petro-Canada	Progas[4]	Shell	Texaco	TCPL[5]
1981	4 699	4 487	4 658	3 853	4 013	4 501	5 092	4 167	4 806	3 774	4 557	4 034.1	4 669
1982	5 083	4 621	4 756	4 252	4 211	4 540	5 233	4 432	4 994	4 214	4 744	4 110.9	4 737
1983	5 323	4 785	4 894	4 427	4 317	4 695	5 379	4 453	5 161	4 283	4 921	4 187.8	4 852
1984	5 480	4 786	4 994	4 365	4 384	4 656	5 424	4 354	5 296	4 369	4 924	4 264.6	4 933
1985	5 835	4 888	5 092	4 388	4 431	4 734	5 521	5 370	5 304	5 320	5 008	4 149.3	5 015
1986	5 993	4 770	5 185	4 431	4 378	4 617	5 499	4 380	5 300	4 121	4 861		5 059
1987	6 091	4 640	5 264	4 470	4 468	4 501	5 471	4 387	5 197	3 783	4 690		5 056
1988	6 021	4 504	5 371	4 520	4 439	4 346	5 502	4 361	5 141	3 435	4 561		5 096
1989	5 935	4 395	5 468	4 567	4 440	4 307	5 430	4 312	5 061	3 091	4 463		5 133
1990	5 836	4 293	5 581	4 594	4 415	4 307	5 324	4 222	4 998	2 824	4 380	4 110.9	5 183
1991		4 137	5 661	4 582	4 309	4 229	5 132	4 038	4 909	2 557	4 266		5 187
1992		4 010	5 715	4 536	4 141	4 190	4 963	3 862	4 797	2 306	4 195		5 169
1993		3 874	5 752	4 497	3 985	4 229	4 941	3 682	4 674	2 103	4 121		5 150
1994		3 702	5 739	4 408	3 834	4 190	4 780	3 490	4 573	1 900	4 013		5 096
1995		3 533	5 702	4 338	3 727	4 229	4 576	3 282	4 437	1 686	3 914	4 956.2	5 026
1996		3 332	5 585	4 241	3 594	4 152	4 400	3 033	4 039	1 526	3 790		4 881
1997		3 212	5 584	4 155	3 513	4 229	4 213	2 769	4 191	1 439	3 745		4 860
1998		3 042	5 433	4 066	3 383	4 229	4 069	2 555	4 039	1 304	3 649		4 702
1999		2 867	5 245	3 934	3 255	4 190	3 874	2 352	3 870	1 171	3 541		4 511
2000		2 690	5 070	3 818	3 103	4 229	3 654	2 185	3 678	1 063	3 447	4 648.8	4 329

(1) Gulf, Norcen - Converted m^3 using 38.8 MJ/m^3.
(2) Consolidated - Case 2 (Most Likely).
(3) Ontario - Case 1 (Accelerated rate of take).
(4) ProGas - NEB Tracking Case - November 1979 Reasons for Decision
(5) TransCanada - High Case.

cents/gigajoule Gas Tax. Other measures in the NEP which adversely affected producers included the redefinition of exploration expense whereby shut-in gas wells would no longer receive an immediate tax write-off, the elimination of the 33 1/3 percent depletion allowance on development expenditures, the phasing out of the 33 1/3 percent depletion on exploration expenditures and a gas price schedule which would decrease producer netback from domestic sales to the end of 1983. Submittors forecast that the level of exploration in the conventional areas would decline in rough proportion to the decrease in cash flow available to the industry. This would result in a decrease in annual gas reserves additions and subsequent deliverability.

Forecasts of reductions in drilling activity varied from between 20 and 50 percent below 1980 levels. Pan-Alberta indicated that some pools already discovered and under contract to it would become uneconomic to develop. Amoco stated that its tight gas pilot project in the Deep Basin, which was marginally economic prior to the NEP, was now cancelled. Because of the adverse effects of the NEP, some production of old gas could be curtailed completely in British Columbia, and there would be a considerable curtailment of exploratory drilling. Chevron cancelled its drilling program in British Columbia for the forthcoming drilling season and had no plans for further activity other than some geophysical programs currently underway. Columbia indicated that gas from the Kotaneelee Field would not be produced because of the 50 percent Canadian ownership requirement. Producers agreed that although the proposed incentive grants would be beneficial to some, they would be outweighed by the negative aspects of the NEP. The proposed Gas Bank was believed to have an insignificant impact on total gas supply.

CPA based its deliverability forecast on the assumption that a market would be available for the gas. It presented a composite forecast by combining the forecasts for gas plant operations and connected reserves in dry gas fields, unconnected established reserves and reserves additions. The unconnected established reserves were arbitrarily assumed to be tied in over five years and produced at a rate of take of 1:7300 for all areas except British Columbia, which was at a rate of 1:8000. Deliverability from reserves additions attributable to appreciation of existing pools was assumed to be available one year after those reserves were booked. New discoveries were forecast to provide deliverability five years after the discovery year. For reserves additions, the same rates of take were used as for unconnected established reserves.

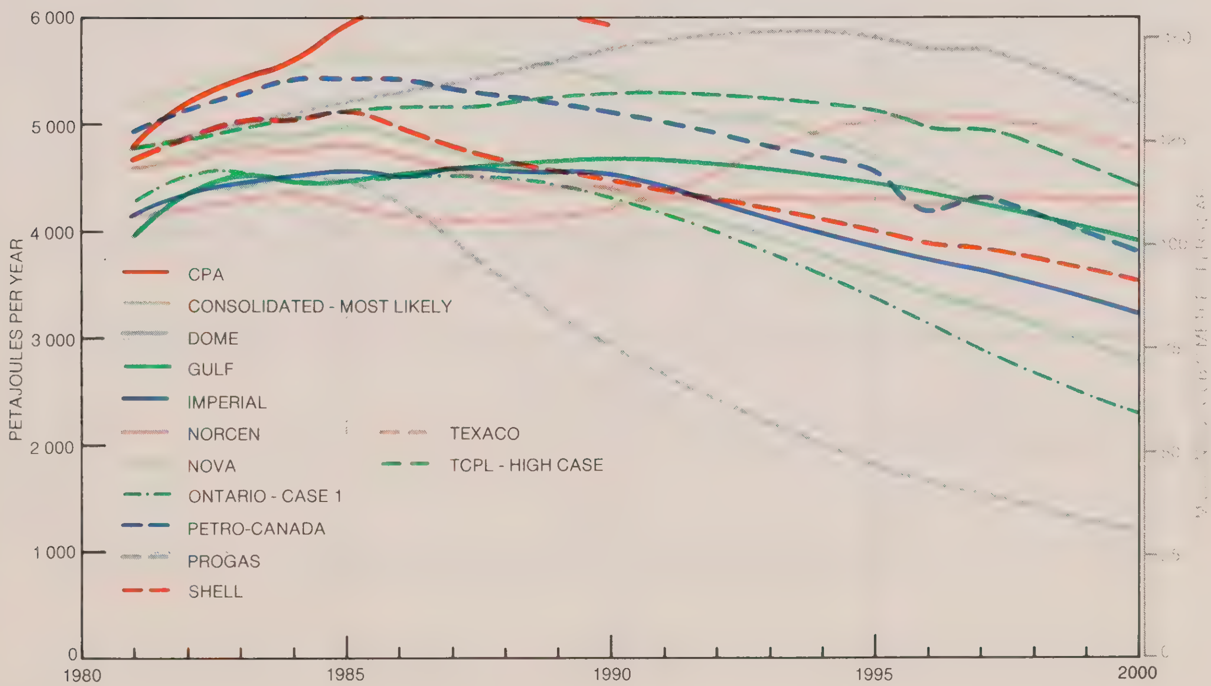

Figure 11-3 Natural Gas Deliverability from Conventional Areas
Comparison of Forecasts: Pre-NEP

Table 11-7

NATURAL GAS DELIVERABILITY FROM CONVENTIONAL AREAS
Submittors' Post-NEP Forecasts
(Petajoules/Year)

Year	Consolidated[2]	Gulf[1]	Norcen[1]	Petro-Canada	Shell	TCPL[3]
1981	4 487	3 833	4 501	4 802	4 557	4 669
1982	4 615	4 190	4 578	4 979	4 742	4 728
1983	4 763	4 307	4 695	5 129	4 900	4 817
1984	4 738	4 163	4 656	5 240	4 870	4 851
1985	4 804	4 109	4 695	5 226	4 897	4 857
1986	4 653	4 062	4 578	5 209	4 683	4 805
1987	4 499	4 024	4 423	5 098	4 426	4 696
1988	4 349	3 993	4 268	5 041	4 203	4 625
1989	4 255	3 965	4 190	4 961	4 004	4 549
1990	4 137	3 927	4 152	4 899	3 818	4 489
1991	3 987	3 853	4 113	4 813	3 605	4 394
1992	3 869	3 756	4 074	4 707	3 440	4 289
1993	3 746	3 670	4 074	4 591	3 282	4 201
1994	3 592	3 550	4 074	4 496	3 097	4 096
1995	3 444	3 457	4 074	4 366	2 932	3 996
1996	3 264	3 341	4 035	4 170	2 752	3 835
1997	3 166	3 251	4 035	4 132	2 665	3 812
1998	3 017	3 158	3 996	3 984	2 533	3 663
1999	2 858	3 030	3 880	3 820	2 401	3 493
2000	2 718	2 922	3 841	3 633	2 289	3 339

[1] Gulf, Norcen - Converted m^3 using 38.8 MJ/m^3.
[2] Consolidated - Pre-NEP Case 1 (Low Case)
[3] TransCanada - Unchanged NEP and limited market case.

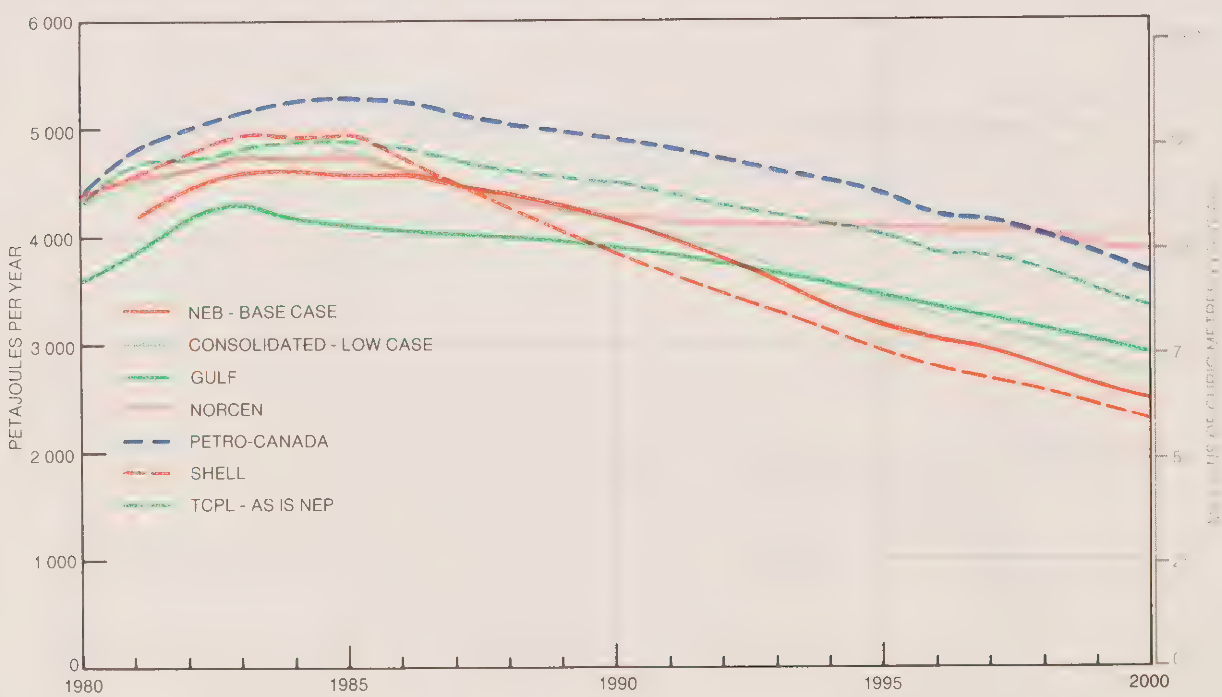

Figure 11-4 Natural Gas Deliverability from Conventional Areas
Comparison of Forecasts: Post-NEP

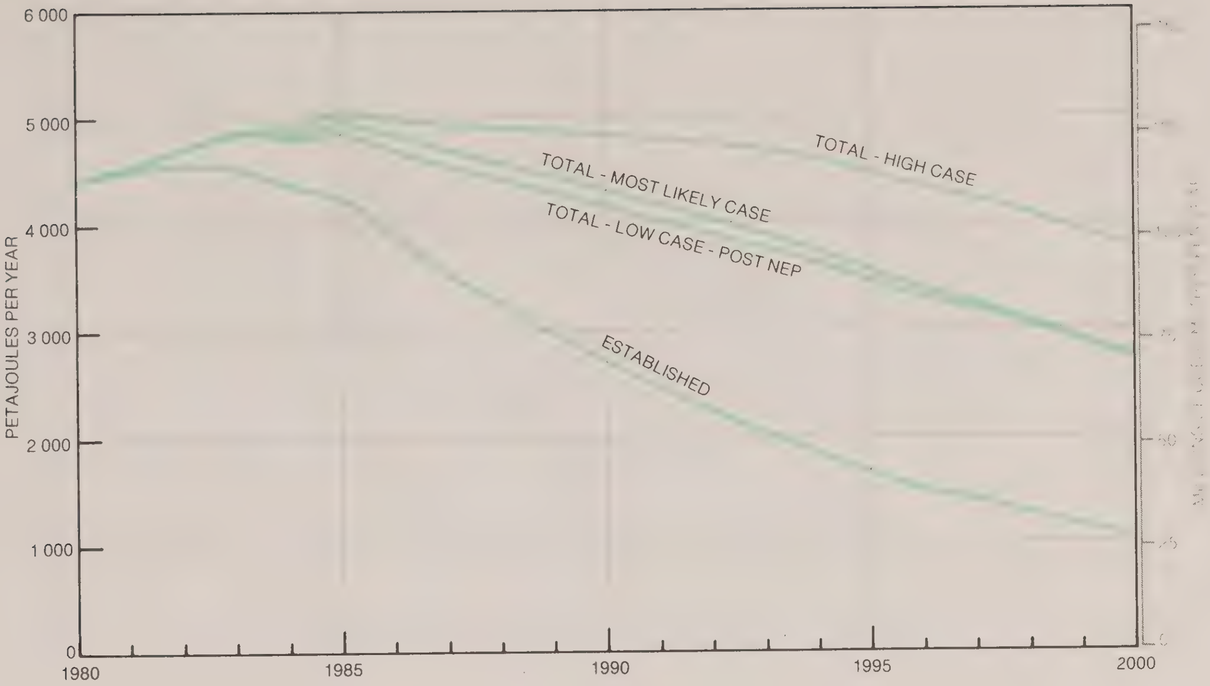

Figure 11-5 Natural Gas Deliverability from Conventional Areas
Consolidated Forecast

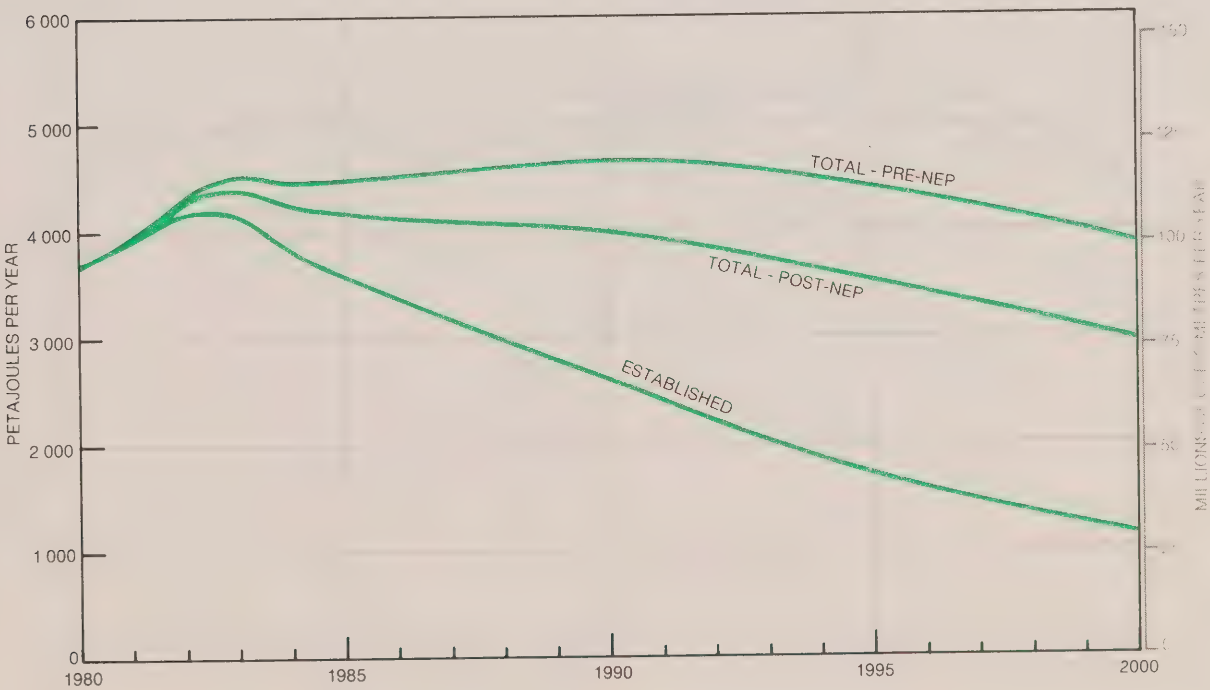

Figure 11-6 Natural Gas Deliverability from Conventional Areas
Gulf Forecast

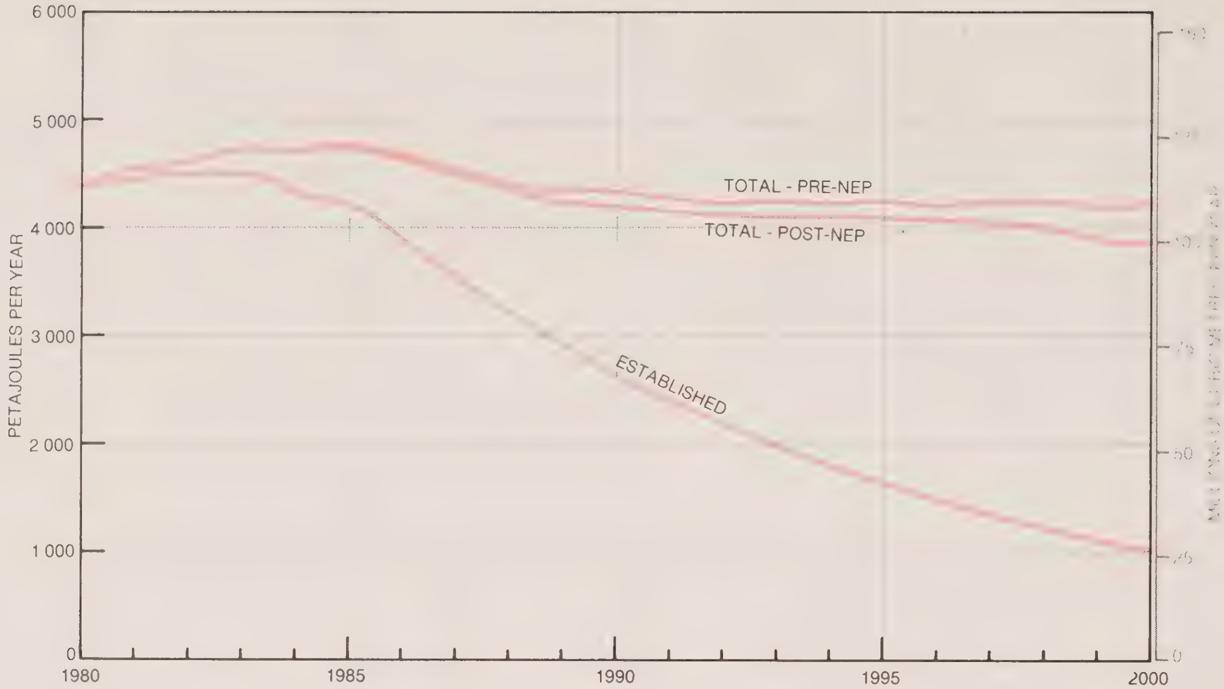

Figure 11-7 Natural Gas Deliverability from Conventional Areas
Norcen Forecast

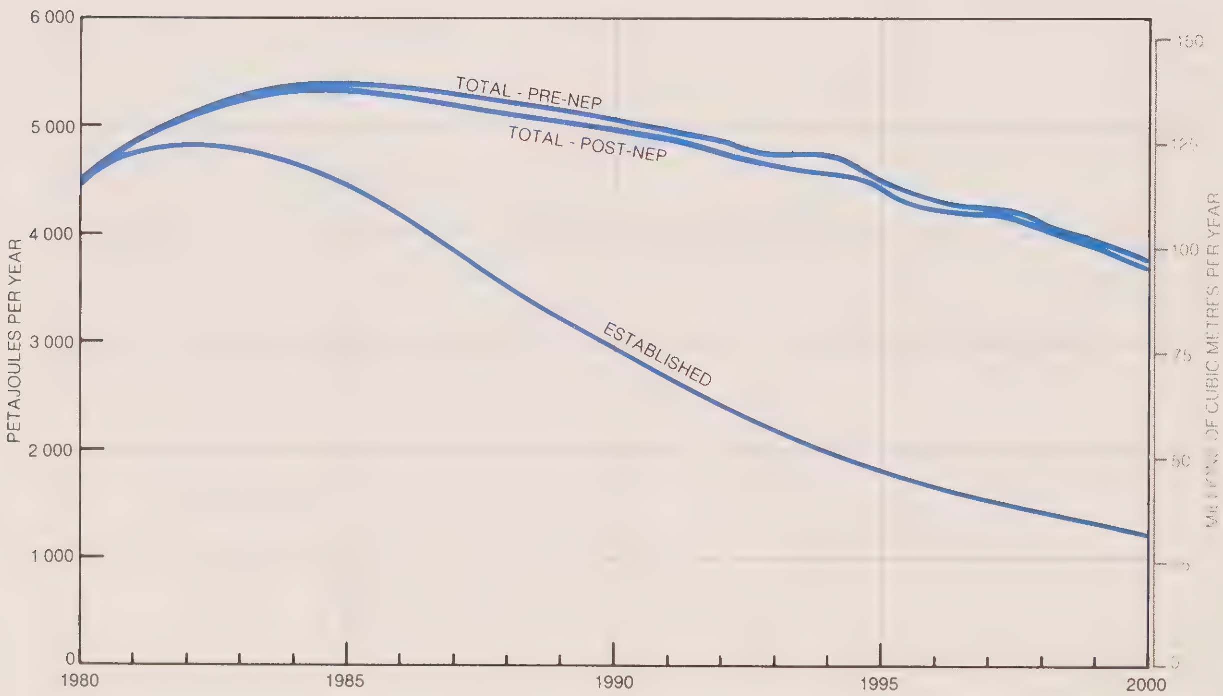

Figure 11-8 Natural Gas Deliverability from Conventional Areas
Petro-Canada Forecast

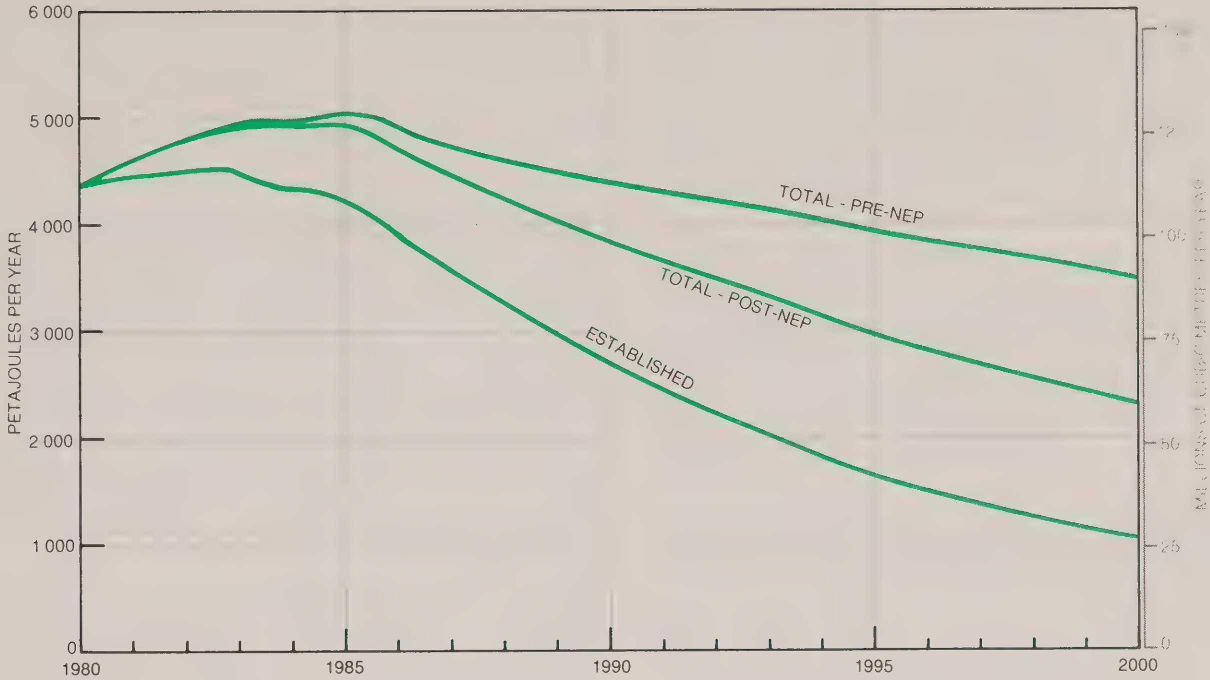

Figure 11-9 Natural Gas Deliverability from Conventional Areas
Shell Forecast

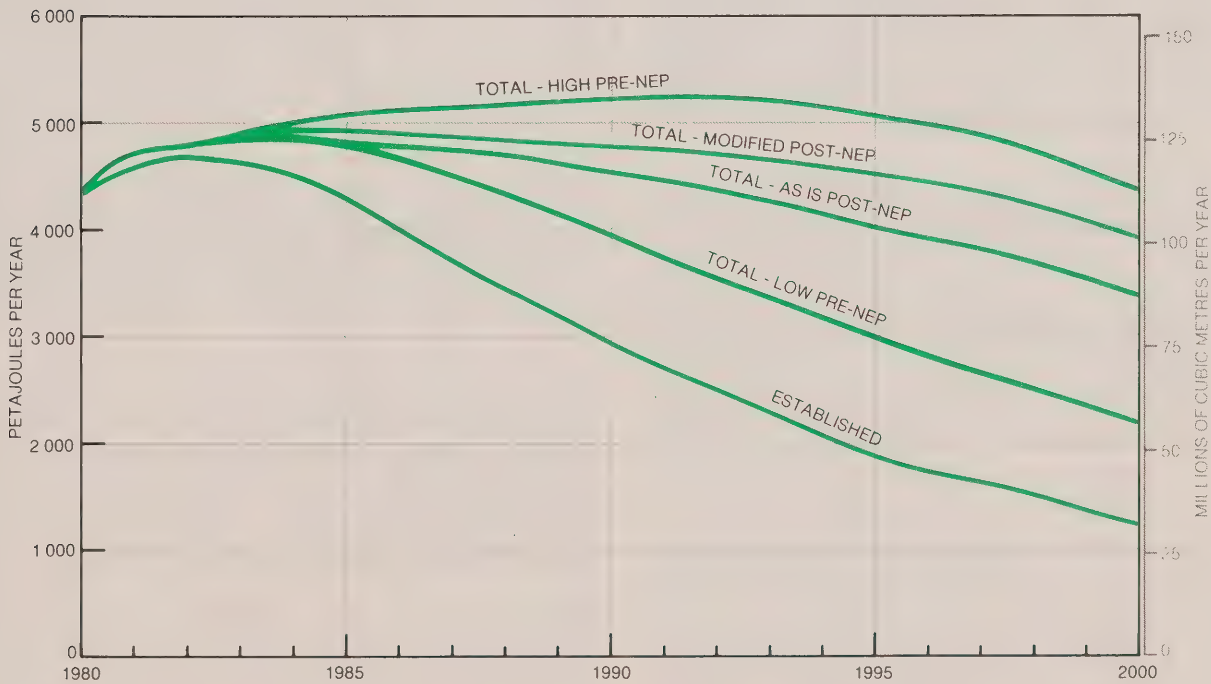

Figure 11-10 Natural Gas Deliverability from Conventional Areas
TransCanada Forecast

CPA did not attempt to evaluate the impact of the NEP on marketable gas deliverability from established reserves or from appreciation of current reserves, although it believed that the negative impact would be significant. CPA stated that the deliverability from new discoveries would be one-third less than it forecast in its pre-NEP estimates. The reduction would total 5 million cubic metres per day in 1985 and 25 million cubic metres per day in 1990.

Consolidated presented three forecasts of natural gas deliverability from conventional producing areas by combining the NEB forecast from remaining established reserves contained in the Board's November 1979 Reason for Decision with its own forecasts of deliverability from projected reserves additions which reflected its low case (Case 1), most likely case (Case 2), and high case (Case 3) demand scenarios. Case 1 assumed no additional exports and that actual deliveries would be less than yearly authorized export volumes. In Case 2, some additional exports were assumed and after 1983 current annual export volumes were forecast to be slightly higher than forecast in Case 1. Its Case 3 was not demand limited and assumed that exports could absorb all surplus natural gas. Deliverability from reserves additions was based on the premise that all the volumes would be connected over a five-year period and produced at a rate of take of 1:7000 until 44 percent of the reserves had been recovered, thereafter the rate of production was declined at eight percent per year.

Consolidated projected that implementation of the NEP would result in a deferment of reserves additions for a number of years, reflecting the anticipated decrease in industry expenditures of about 30 percent. The expected effect of the NEP on supply was to modify the rate at which reserves were added. However, in the long run, it was expected that the same total additions to reserves would occur as if the NEP had not been implemented. Consolidated considered its low case to be the most realistic forecast reflecting the effects of the NEP.

Dome's supply forecast reflected its assumption of Canadian capacity to produce, unrestricted by demand, during the period 1980 to 2000 inclusive. Dome adopted TCPL's estimate of deliverability from current reserves under contract to TCPL and ProGas, and estimates of deliverability from other transmission companies. Also included was the deliverability from TCPL's estimate of uncommitted reserves and AERCB's deferred reserves. Deliverability from reserves additions was added over a seven-year period commencing the year following discovery. All reserves were assumed to produce at a rate of take of 1:7300 until 50 percent of the reserves were produced then the deliverability was declined at a rate of ten percent per year.

Gulf's pre-NEP forecast of supply was based on the CPA's estimate of remaining established reserves as of 31 December 1979, together with its own assessment of supply from projected reserves additions. It assumed unrestricted markets, continued high activity and that the producers' relative share of future gas prices would be maintained at current levels. Gulf forecast that reserves additions would be connected over a six-year period in British Columbia. Initial rates of take of 1:5750 for shallow gas and 1:7300 for deep gas were assumed. For all the gas reserves connected in a particular year, the assumed flat life was nine years then the deliverability was declined nine percent per year. In Alberta, shallow gas reserves additions were connected over a four-year period. The initial rate of take was assumed to be 1:4400 with a flat life of two years, thereafter the deliverability was declined nine percent per year. Low sulphur deep gas reserves were produced at a rate of take of 1:7300 with a flat life of five years after which the deliverability was declined at 6.5 percent per year. For the other deep gas reserves, a rate of take of 1:7300 and a ten-year flat life followed by a decline in deliverability of nine percent per year was assumed.

In its post-NEP assessment of supply, Gulf concluded that because of higher revenue taxes and lower than expected natural gas price increases, the cash flow available for reinvestment would be lower, thus the level of the industry exploration activity would be significantly reduced and, consequently, additions to gas reserves would be smaller. Gulf stated that cash flow constraints, coupled with market uncertainties, had resulted in a 33 percent reduction in exploration and development activity for natural gas in Western Canada since its original submission in September 1980. For its revised supply forecast, Gulf did not anticipate a change in the connection rates for reserves additions.

Imperial's forecast of available Canadian natural gas supply was based on the assumption that markets would be unlimited and that price and revenue sharing terms would be adequate. Normal contractual conditions, processing plant capacity, and restrictions on volumes of gas produced in association with oil were also considered. Imperial's forecast of deliverability from conventional producing areas combined the deliverability from currently producing reserves, undeveloped reserves and reserves from future discoveries. Although not evident in its total forecasts, Imperial did illustrate high and low levels of deliverability from undeveloped reserves and future discoveries which reflected reservoir performance and activity levels resulting from producer netbacks and future market access. Imperial assumed that discoveries would be delineated at an average annual rate of 20 percent over a five year period, with production commencing four years after delineation at an initial rate of take of 1:7300.

As a result of the NEP, Imperial indicated that, directionally, natural gas deliverability was expected to be lower than in its pre-NEP forecast. Deliverability from existing pools was expected to be lower as a result of poorer economics in producing marginal pools and wells. Lower forecasts of supply from reserves additions were expected since NEP proposals would reduce the number of economically attractive drilling prospects.

Norcen presented a total supply forecast which assumed that gas prices would continue to increase yielding higher producer netbacks, resulting in more new gas discoveries. As a base for its forecast from existing reserves, Norcen used the reserves estimates as published by the provinces except for Ontario and Southern Territories where NEB volumes were utilized. The deliv-

erability forecast from reserves additions was based on the assumption that all the reserves would be connected over an eleven-year period and they would be produced at rates which would be a mix of 1:7300 rate of take and deliverability type contracts. A flat life of twelve years was assumed following which the deliverability was decreased ten percent annually.

Norcen forecast that the NEP would not change the supply from existing reserves. It was acknowledged that development investment would be adversely affected by the NEP and that production from existing conventional reserves, especially in British Columbia, would be lower than originally forecast. However, Norcen was unable to quantify the magnitude of the effect the NEP would have on development investment. Supply from reserves additions was adjusted to reflect its revised forecast of additions resulting from a projected decrease in exploration drilling during the 1980s and an increase during the 1990s. Additionally, the combination of longer shut-in periods and a long connection profile resulted in a slightly lower total supply forecast.

NOVA presented two "unconstrained" deliverability forecasts for the conventional areas. For its remaining established reserves base, NOVA adopted the British Columbia Department of Mines and Petroleum Resources estimates and adjusted estimates of the AERCB as of 31 December 1979. For Saskatchewan and the Yukon Territories, estimates from the NEB November 1979 Reasons for Decision were used. Based on its estimate of 96.0 exajoules of undiscovered potential in the Western Canada Sedimentary Basin and its perception of reserves appreciation, NOVA developed a base case and low case of annual reserves additions. The connection schedule for all trend additions was based on the NEB schedule of November 1979 with total volumes being connected in a ten-year period following discovery. The rate of take used was 1:7000 with a flat deliverability life assumed until 40 percent of the reserves had been produced, then deliverability was declined at approximately ten percent per year thereafter.

Although NOVA did not submit a revised forecast of supply showing the effects of the NEP, it did indicate that in total, reserves additions would decline by one-third over the 20-year period, and its low case would be a reasonable approximation of the impact of the price schedules set forth in the NEP.

Ontario's forecast of supply, although unconstrained by markets, was limited by timing of facilities, contractual obligations, and efficiency of production. The forecast reflected the recent considerable increase in industry activity. Ontario submitted a total Canada supply forecast by province or area from currently established reserves in which it used reserves estimates of the various contracting purchasers for Alberta gas. Ontario also considered two supply cases from trend additions in Alberta, other provinces and areas based on the premise that activity levels would be maintained throughout the forecast period and connection rates would be accelerated with time, resulting in a more rapid availability of gas from reserves additions. Case 1 assumed a rate of take for Alberta in the order of 1:5475 reflecting recent deliverability type and rates of take contracts, however, to allow for operating inabilities and other factors, an effective rate of take of 1:6000 was used. Case 2 assumed a standard twenty-year contract rate of take of 1:7300 reduced to 1:7680 after allowing for operational difficulties. For British Columbia and the Northwest and Yukon Territories, currently prevailing rates were assumed to continue. Deliverability was assumed to have a flat life which varied from seven years in British Columbia to eleven years in Alberta, following which deliverability was declined exponentially at 9.6 percent and 12.3 percent respectively in Cases 1 and 2.

In its assessment of the effects of the NEP, Ontario indicated that trend additions would be 20 percent lower in the early years because of the anticipated slowdown in drilling activity. The level of deliverability would also be somewhat less than previously forecast, reflecting the lower rate of additions. Ontario believed that Case 1 (accelerated contract rates) was unlikely to materialize.

Petro-Canada's forecast was based on the assumption of a downturn in exploratory activity in Western Canada in the early 1980s due to the delay in bringing new reserves to market. This resulted in a 30 percent decline in reserves additions. It assumed that market conditions would improve and exploratory activity would return to higher levels by the mid-1980s. Its forecast of supply from established reserves incorporated the latest system supply forecasts of TCPL, Pan-Alberta, and A & S. The NEB forecast of supply from other established reserves was adopted from the Board's November 1979 Reasons for Decision. Forecasts from reserves additions were derived from consultants' and Petro-Canada's in-house studies.

For its post-NEP supply forecast, Petro-Canada assumed that there would be a further ten percent decrease in reserves additions in the short-term, with a recovery in the mid-1980s as a result of improved markets and the higher NEP prices. It assumed an overall decrease of about five percent in deliverability for the forecast period which mainly affected the near term.

ProGas's forecast of natural gas supply from conventional areas was based mainly on its review of the findings of the NEB in its 1979 Gas Report and its November 1979 Reasons for Decision, and a review of the reserves estimates made by various provincial authorities. ProGas believed that the Board's forecast of future trend gas additions was reasonable. It adopted the NEB's latest "tracking case" supply forecast rather than the capability forecast of November 1979 because it believed the former adequately reflected the manner in which supply could be derived from current and future reserves and more closely reflected the practicable supply availability.

Shell based its forecast of total deliverability from the conventional areas on the assumptions that the high levels of exploration would continue, any gas surplus to Canadian requirements would be exported and export pricing problems would be resolved. It combined the NEB's November 1979 deliverability forecast from established reserves with its own assessment of deliverability from appreciation of existing reserves and reserves additions. For the deliverability from appreciation of existing reserves, production was assumed to start one year after the reserves addition was booked and forecast on a life index basis

determined from data in the November 1979 Reasons for Decision. Shell's forecast of deliverability from reserves additions was based on its estimate of 63.9 exajoules being discovered and 60.9 exajoules being developed by 2000. Annual quantities were segregated into Class 1 (deep), Class 2 (intermediate depth), and Class 3 (shallow) reservoirs — each class having its own development and production characteristics. Delays of six, four, and one year(s) were adopted between proving up reserves and start of production for Classes 1, 2, and 3 respectively. The gas was assumed to be produced during the flat life at a rate ten percent higher than a rate of take of 1:8000 for British Columbia and Saskatchewan, and ten percent higher than 1:7300 for Alberta. For Class 1, 2 and 3 reservoir types, flat life periods were assumed to be 12, 8.2 and 7.3 years respectively, followed by corresponding initial decline rates of 24, 8, and 7.5 percent.

In Shell's post-NEP assessment of natural gas supply from conventional producing areas, the only change from its previous forecast was a decrease in new discoveries to reflect decreased exploration activity. The deliverability from these new discoveries fell to 60 percent of its previous estimate by 1987.

As a basis for its gas deliverability forecast, Texaco assumed no major change in government policies with respect to royalties, taxes and revenue-sharing programs. Gas prices were assumed to escalate.

Texaco derived its forecast of natural gas deliverability by using the Board's November 1979 supply forecast from current reserves as a base, and incorporating the deliverability anticipated from its estimate of gas reserves additions for Western Canada exclusive of the Deep Basin. Texaco made a separate forecast of deliverability from anticipated reserves additions of 730 billion cubic metres attributable to the Deep Basin, and indicated that about 75 percent of these additions would be from conventional high productivity type pools and would be producing around 1990.

In estimating the deliverability forecast of its own system, TCPL changed from a collection point to a dispatch group basis to further refine and reflect those production units that deliver to a collection point and have similar contract terms. The use of dispatch groups enabled TCPL to appraise production characteristics of the primary production unit with respect to wells, compression, processing plant, unit agreements and economic decisions. As a basis for its deliverability forecast, TCPL assumed that demand was not a constraint. It presented two deliverability forecasts: a high case which assumed increased industry activity for five years at the established last five years' rate, followed by a levelling off for five years before starting a slight decline; and a low case which assumed that industry activity would deteriorate completely, resulting in annual drilling approaching 1970 levels within five years. Connection rates and deliverability profiles for both the uncommitted reserves and reserves additions were adopted from the NEB November 1979 Reasons for Decision. It was assumed that no uncommitted gas would be connected in 1980. The reserves beyond economic reach were connected at a rate of four percent per year starting in 1981, and were produced at a 1:7000 rate until 40 percent of the reserves were depleted, following which production was declined at ten percent per year.

TCPL's total Canada supply forecast for the conventional producing areas was based on an aggregate of deliverability forecasts for various supply sources including reserves under its control, volumes from ProGas, reserves under contract to other transmission companies, Pan-Alberta reserves, and reserves under contract to Alberta utilities. Also included in the total Canada deliverability were forecasts from its estimate of reserves additions, deferred reserves, and reserves beyond economic reach. TCPL used the NEB November 1979 deliverability forecast from uncommitted reserves in British Columbia, and its own forecast for Alberta.

To show the effects of the NEP, TCPL developed deliverability forecasts based on two scenarios of decreased drilling activity and resulting reserves additions. For its first case, TCPL assumed limited markets and no modification to the NEP. For its second case, it assumed adequate incentives through market opportunities and/or a modified NEP.

Views of the Board

The Board employed its computerized gas deliverability model to forecast deliverability from established reserves. The Board's forecast of supply from reserves under the control of major gas purchasers is presented in Table 11-8. The forecast is based on a pool-by-pool analysis of gas deliverability reflecting well flow characteristics, basic reservoir parameters, and daily contract rates. The Board's model uses drilling and compression cost data to determine the degree to which it would be economical to maintain deliverability from a pool as close to the contract rate as possible by drilling infill wells and/or adding field compression. The model incorporates the producer forecasts for solution and associated gas production available to the appropriate gas transmission system. The results for each of TCPL, A & S, WTCL (Licence GL-41 and GL-4 supply areas), Pan-Alberta (AERCB Permit No. 79-2 fields), ProGas, Sulpetro, Canadian-Montana, and Columbia are shown in Table 11-8.

The remaining components of the supply forecast from controlled reserves were derived as follows:

1. The forecast for the Alberta utilities submitted by the Joint Applicants at hearing GH-4-79 was adjusted to exclude deliverability from those deferred reserves under control of the Alberta utilities and adopted by the Board.
2. Pan-Alberta's forecast for its AERCB Permit No. 80-3 fields submitted to hearing GH-4-79 was adopted.
3. The Many Islands Pipelines and Saskatchewan production forecasts were adopted from the SPC submission to this Inquiry.
4. The forecast of production from Ontario was estimated by the Board based on production history.

It should be noted that non-contracted gas reserves in British Columbia and the Southern Territories, as of 31 December

Table 11-8

NEB FORECAST OF NATURAL GAS DELIVERABILITY FROM CONTROLLED RESERVES
(Petajoules/Year)

Year	TCPL	A & S	WTCL GL-41	WTCL GL-4	Pan-Alberta PA-80-3	Pan-Alberta PA-79-2	Alta. Utilities	Many Islands	Canadian Montana	Production East of Alberta	Columbia	Pro-Gas	Sulpetro	Total[1]
1981	2 018	587	502	41	106	116	366	19	26	59	14	79	27	3 959
1982	1 972	577	511	34	93	333	354	18	21	64	14	96	25	4 111
1983	1 906	560	500	29	81	436	342	20	17	60	14	103	24	4 091
1984	1 836	523	500	24	71	394	318	22	14	64	14	102	23	3 904
1985	1 746	492	484	13	62	356	286	22	12	63	14	99	22	3 672
1986	1 694	493	458	4	54	313	261	20	10	60	14	94	21	3 493
1987	1 570	452	423	4	48	274	234	18	9	57	14	86	21	3 209
1988	1 472	419	398	4	41	245	220	16	7	53	14	78	20	2 987
1989	1 357	371	363	4	36	217	201	15	7	50	14	70	20	2 724
1990	1 253	346	333	4	32	184	186	13	6	46	14	63	20	2 500
1991	1 115	318	293	4	27	161	174	11	5	44	14	56	17	2 239
1992	1 005	293	282	4	24	144	162	10	5	41	6	50	14	2 039
1993	903	263	253	4	21	131	142	9	4	39	1	45	12	1 827
1994	791	233	232	4	19	121	132	8	4	36	0	40	11	1 631
1995	658	169	207	4	16	111	123	7	4	35	0	35	10	1 378
1996	577	143	178	4	14	101	108	6	4	32	0	31	9	1 206
1997	496	127	67	4	13	92	98	6	4	30	0	28	8	1 072
1998	406	113	154	3	11	84	89	5	3	28	0	20	8	924
1999	335	97	140	0	10	77	81	4	3	25	0	18	7	798
2000	283	85	127	0	8	72	71	4	3	23	0	16	6	698

[1]Totals may not add due to rounding.

Table 11-9

NEB FORECAST OF NATURAL GAS DELIVERABILITY FROM CONVENTIONAL AREAS
(Petajoules/Year)

	Deliverability from Established Reserves								Supply from Reserves Additions			
Year	Total Controlled	Reserves Revision[1]	S.E. Alta. Uncom-mitted	Other Alta Uncom-mitted	B.C. 1980 Additions	Alta. B.E.R.	Alta. Deferred	Total	Alberta	B.C.	Sask.	Total[2] Canada Supply Capability
1981	3 959	–27	118	79	0	2	3	4 133	18	3	0	4 153
1982	4 111	–45	118	158	0	3	3	4 349	58	9	0	4 416
1983	4 091	–43	118	237	0	5	3	4 412	127	19	1	4 559
1984	3 904	–52	118	316	4	7	4	4 301	229	34	2	4 566
1985	3 672	–68	117	395	8	8	6	4 139	344	52	3	4 537
1986	3 493	–71	116	448	12	10	6	4 015	454	69	4	4 541
1987	3 209	–50	115	474	17	12	6	3 782	558	85	6	4 430
1988	2 987	–47	108	490	21	14	12	3 585	658	100	9	4 351
1989	2 724	–53	102	499	24	15	27	3 338	751	115	11	4 214
1990	2 500	–50	96	497	25	17	42	3 127	836	128	14	4 105
1991	2 239	–42	73	485	26	18	39	2 836	912	140	17	3 905
1992	2 039	–57	58	467	26	19	35	2 588	976	150	20	3 734
1993	1 827	–74	54	439	26	20	32	2 325	1 028	159	23	3 534
1994	1 631	–134	46	410	25	21	28	2 027	1 070	166	25	3 288
1995	1 378	–41	43	380	25	22	46	1 853	1 101	171	28	3 153
1996	1 206	–9	39	352	23	23	45	1 680	1 122	175	30	3 007
1997	1 072	–9	35	325	22	24	100	1 567	1 135	177	32	2 911
1998	924	–5	27	299	20	24	97	1 386	1 141	179	33	2 738
1999	798	–3	21	275	19	25	95	1 229	1 140	179	33	2 580
2000	698	–6	18	252	17	26	112	1 117	1 133	178	32	2 460

(1) This column represents the net effect on deliverability of the Board's 1.4 EJ downward revision to its year-end 1979 reserves estimate. This adjustment was applied to the total deliverability from controlled reserves as shown in Figures 11-11 and 11-12.

(2) Totals may not add due to rounding.

1979, were considered to be controlled by WTCL for the purpose of the Board's WTCL forecast whereas the reserves additions for 1980 were treated as uncommitted reserves. The effect on deliverability of the Board's downward revision of some 1.4 exajoules to its year-end 1979 reserves estimate for Alberta is shown on Table 11-9. Alberta reserves, as of 31 December 1980, which were not included in the controlled reserves forecast, were classified into three categories — uncommitted, deferred and beyond economic reach.

The Board now estimates that as of 31 December 1980 there were some 11.8 exajoules of uncommitted gas reserves in Alberta. The Board estimates that of the 11.8 exajoules of uncommitted gas in Alberta, some 1.7 exajoules were Southeastern Alberta shallow gas reserves. Deliverability from all the Southeastern Alberta shallow gas reserves was forecast using the Board's computer model and that portion attributable to the 1.7 exajoules of uncommitted shallow gas reserves is shown in Table 11-9. The remaining 10.1 exajoules of uncommitted Alberta gas reserves were connected as in the Board's November 1979 Reasons for Decision (i.e., percent connection by year of 15, 15, 15, 15, 15, 10, 5, 3, 3, 2, 1, 1). The 0.5 exajoules of reserves treated as uncommitted in British Columbia were connected according to the same profile commencing in 1984, as suggested by WTCL.

The Board has adopted the AERCB estimate of deferred reserves in Alberta of some 3.5 exajoules. TCPL's forecast of deliverability from these deferred reserves was considered reasonable and was adopted. TCPL's forecast for deferred reserves excludes some 0.4 exajoules of deferred reserves under contract to TCPL. The Board has included TCPL's deferred reserves in its forecast of TCPL's system supply.

The Board has adopted AERCB's estimate of 1.6 exajoules of reserves beyond economic reach in Alberta and has treated them in the same manner as in its November 1979 Reasons for Decision. Fifty percent of these reserves were assumed to be available during the forecast period and were connected at a rate of four percent per year.

The deliverability profile employed for uncommitted reserves and reserves additions, although similar to that employed previously, has been adjusted to completely produce the reserves base. The profile is based on an initial rate of take of 1:7000 and a flat life of eight years with production declining thereafter at 8.22 percent per year.

Reserves additions were connected at the same rate as in the Board's November 1979 Reasons for Decision (i.e., percent connection by year of 10, 15, 20, 25, 15, 5, 2, 2, 1, 1, 1, 1, 1, 1) and were produced using the deliverability profile described above.

The Board's forecast of total Canada gas deliverability is detailed in Table 11-9 and is illustrated in Figure 11-11. Figure 11-12 demonstrates the significance of infill drilling and added compression on the deliverability from controlled reserves alone. Figure 11-13 illustrates the potential range of total gas deliverability employing deliverability from the Board's three reserves additions forecasts.

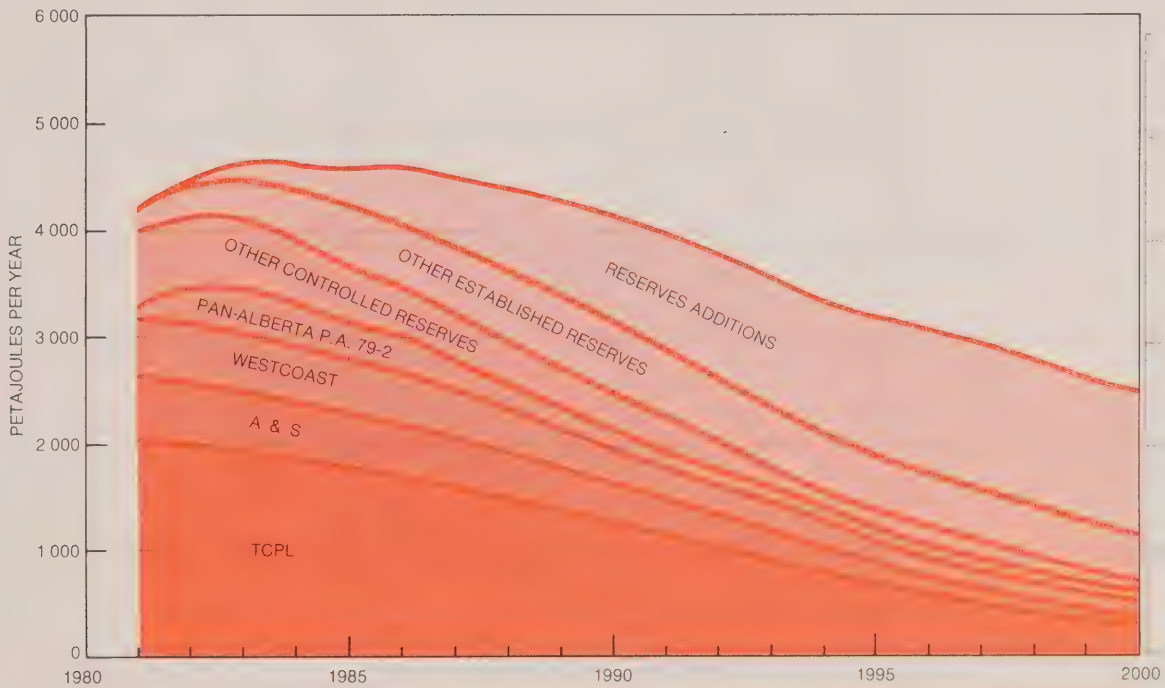

Figure 11-11 Natural Gas Deliverability from Conventional Areas
NEB Forecast

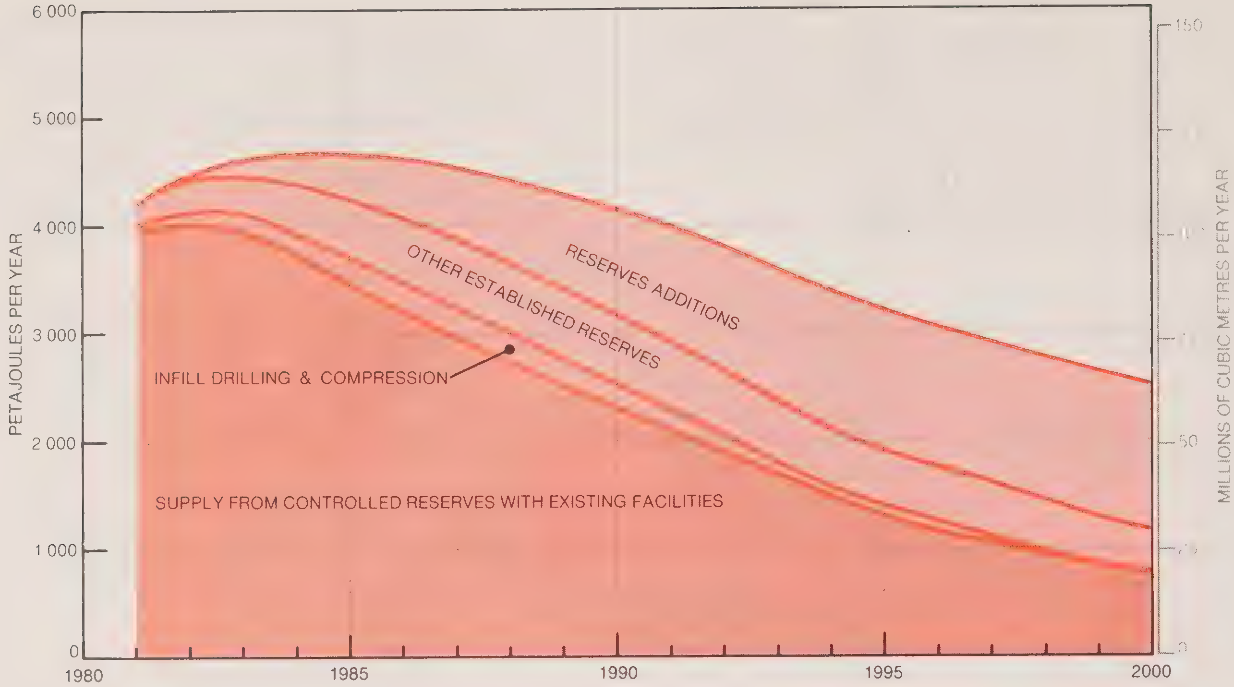

Figure 11-12 Natural Gas Deliverability from Conventional Areas
Effect of Development Using Post-NEP Netbacks
NEB Forecast

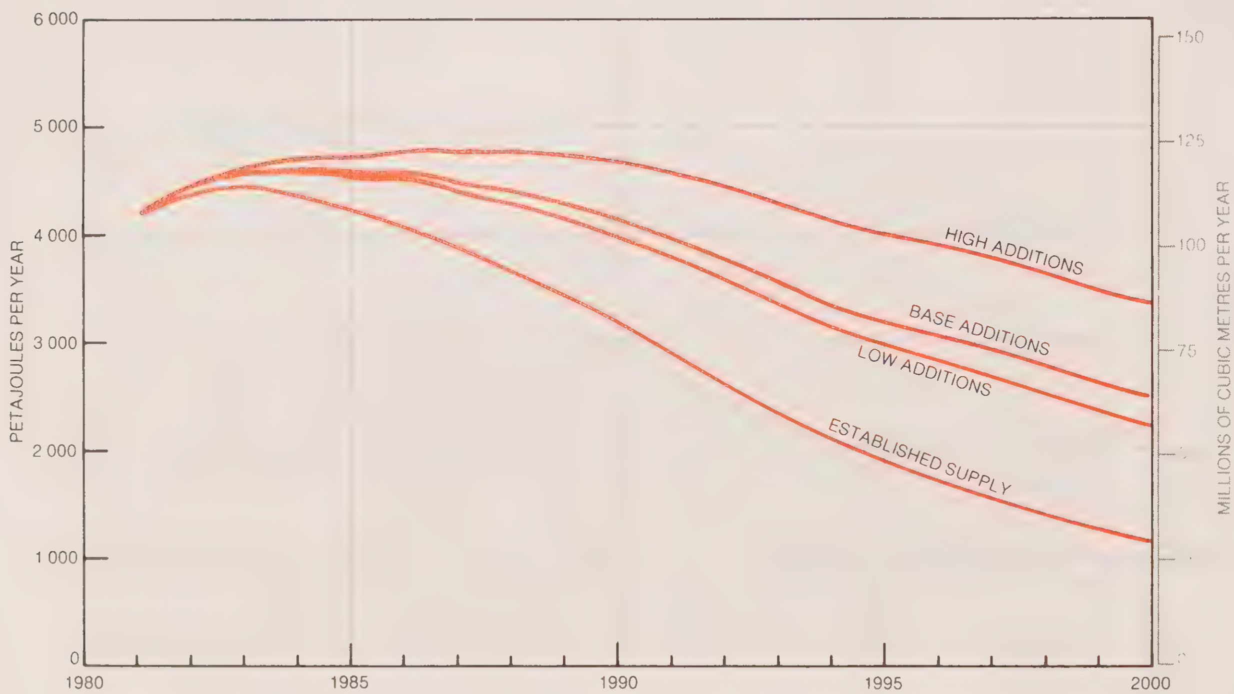

Figure 11-13 Natural Gas Deliverability from Conventional Areas
Range of NEB Forecasts

11.3 Frontier Areas

11.3.1 *Reserves*

Views of Submittors

The gas reserves estimates of Submittors, for Canada's frontier areas, are compared in Table 11-10. Individual field estimates for the Arctic Islands received from two Submittors, are compared in Table 11-11.

No estimates were received of volumes of gas discovered in the Beaufort Sea (other than in that sector adjacent to the mainland coast considered part of the Mackenzie Delta area) or off the Labrador coast. However, Petro-Canada submitted well test data and noted encouragement provided by the discovery of gas and condensate at four wells off the Labrador coast. Submittors assessing the volume of gas found on the Scotian Shelf confined their estimates to structures in the Sable Island area, namely, Venture, Thebaud and Citnalta and emphasized the approximate nature of the estimates.

The general feeling among Submittors was that while there was a large potential for gas reserves in the Beaufort Sea, and on the East coast continental margins, these areas were still at an early stage of exploration, and further drilling would be required to determine established reserves.

In previous submissions to the Board, Panarctic took the position that gas reserves in the Arctic Islands should not be included in Canadian supply when determining surplus. At this inquiry, however, Panarctic requested that the Board give consideration to the inclusion of some Arctic Islands gas reserves because of the proposed Arctic Pilot Project.

Views of the Board

No new data were received on pools in the Mackenzie Delta area, hence the Board has not changed its previously published estimates of established reserves. In the Arctic Islands, established reserves were assigned to the Char and Whitefish fields, increasing the Board's estimate for the Islands to 12.0 exajoules from 9.7 exajoules. No reserves were assigned to the Roche Point field as the Board is not satisfied these should be considered in the established category at this time.

While discoveries of natural gas have been made in the Beaufort Sea, on the Scotian Shelf, and in the offshore areas of Newfoundland and Labrador, the Board believes it would be premature to assign established reserves to these areas at this time. Additional drilling will be required before the commercial significance of these areas can be determined.

The Board's estimates of established reserves are included in Tables 11-10 and 11-11.

11.3.2 Deliverability

Views of Submittors

For its forecast of natural gas supply from the frontier regions, Consolidated projected that the Arctic Pilot Project (APP) would commence deliveries of LNG of 125 petajoules per year by 1985 in each of its three cases. In its low case (Case 1), this quantity of 125 petajoules was maintained to the year 2000. Supply from other frontier areas was not included. For the most likely case (Case 2), the 125 petajoules per year were maintained until 1993, then increased to 250 petajoules and held at this level to the end of the forecast period. An additional frontier supply of 500 petajoules per year was forecast for 1995 continuing at that level to the year 2000. For the high case (Case 3) the APP supply of 125 petajoules was maintained until 1992, then increased to 375 petajoules. The Mackenzie Delta and other frontier areas were forecast to begin producing in 1995, each supplying 500 petajoules per year to the year 2000.

For the frontier areas, Dome presented a forecast of gas deliverability showing a low and high estimate around an expected

Table 11-10

ESTIMATES OF MARKETABLE NATURAL GAS RESERVES
FRONTIER AREAS
(September 1980)
(Exajoules)

	CPA(1)	Petro-Canada	Gulf(1)	Consolidated	Imperial(1)	Ontario(1)	Panarctic	Dome(1)	NEB Estab.
Mackenzie Delta - Beaufort Sea Area(2)	(3)	6.9(4)	7.1	5.5	9.5	5.7— 8.6	—	7.3(6)	5.6
Arctic Islands	22.1(3)	17.0(5)	15.1	13.1	17.5	17.1—20.9	15.7(6)	13.3(6)	12.0
East Coast Offshore	—	—	4.3	—	—	1.1— 2.3	—	10.1(7)	—
Scotian Shelf only	—	2.1	—	—	2.2	—	—	—	—

(1) In order to compare, the Board converted the submitted units to exajoules, using an arbitrary conversion factor of $38 MJ/m^3$.
(2) Includes only near-shore Beaufort Sea reserves.
(3) Mackenzie Delta-Beaufort Sea Area and Arctic Islands grouped.
(4) CPA estimate.
(5) Panarctic estimate of proved, probable, and possible reserves.
(6) Proved and probable reserves.
(7) Probable reserves.

Table 11-11

ESTIMATES OF MARKETABLE NATURAL GAS RESERVES BY FIELD
ARCTIC ISLANDS
(September 1980)
(Exajoules)

	PANARCTIC[1]			DOME[1]			NEB
	Prov. & Prob.	Possible	Total	Prov. & Prob.	Possible	Total	Established
Char	0.4	—	0.4	0.5	—	0.5	0.4
Drake Point	5.6	0.3	6.0	5.7	0.3	6.0	4.2
Hecla	3.8	0.2	4.0	3.8	0.2	4.0	2.7
Jackson Bay	1.2	—	1.2	1.2	—	1.2	1.1
King Christian Is.	0.6	—	0.6	0.6	—	0.6	0.5
Kristoffer Bay	0.7	0.5	1.2	0.7	0.5	1.2	0.7
Roche Point	0.5	—	0.5	(2)	(2)	(2)	—
Thor	0.8	—	0.8	0.8	—	0.8	0.7
Wallis	0.1	—	0.1	0.1	1.5	1.6	0.1
Whitefish	2.0	0.6	2.6	(2)	(2)	(2)	1.7
Total[3]	15.7	1.6	17.3	13.3	2.5	15.8	12.0

(1) Converted to exajoules using an arbitrary conversion factor of 38 MJ/m^3
(2) No estimate provided.
(3) Totals may not add due to rounding.

supply case. Dome stated that its forecast could be realized if adequate incentives in the form of market access, price, royalties and taxes at levels that would encourage exploration and development were available. For the Mackenzie Delta-Beaufort Sea area, Dome predicted movement of gas by LNG tanker or pipeline to southern markets. For purposes of its forecast, the latter alternative was chosen assuming a Dempster lateral or the Polar Y-line.

Production, based on the development of proven and potential reserves, was assumed to commence by 1988 from its projected 1990 discovered and proven reserves of between 420 and 450 billion cubic metres. Initial production rates for the high, low and expected cases were 14.0, 7.0 and 9.9 million cubic metres per day respectively, increasing to 74.7, 42.3 and 62.0 million cubic metres per day respectively by the year 2000.

Dome considered two transportation systems for the Arctic Islands in its forecast: the Arctic Pilot Project, assumed to commence operations in 1985 and the Polar Gas Pipeline in 1990. Dome's production forecast began at 3.82 million cubic metres per day for the Arctic Pilot Project increasing to 7.65 million cubic metres per day until 1990 when the Polar Gas Pipeline was assumed to commence operation. At that time the production increased to 45.89 million cubic metres per day subsequently increasing to 49.21 million cubic metres per day, a level which was maintained to the year 2000.

Although Gulf recognized the potential for natural gas supply from various frontier areas, it restricted its supply forecasts to two areas based on its assumption of transportation links from the Mackenzie Delta and the Arctic Islands. Gulf estimated production from the Mackenzie Delta would commence in 1995 at 8.2 billion cubic metres and from the Arctic Islands in 1986 at 2.3 billion cubic metres. Total producibility from both the Mackenzie Delta and the Arctic Islands would reach 36.2 billion cubic metres per year by 2000. For the Sable Island area, Gulf estimated that production would commence in 1987 at 4.1 billion cubic metres per year declining to 3.0 billion cubic metres per year by the year 2000.

In its forecast of deliverability from the Mackenzie Delta-Beaufort Sea region, Imperial assumed that production would start in 1992 through the Dempster link further assuming that the Alaska gas pipeline would be completed in 1987. Imperial forecast eight to ten years would be needed to fully develop new discoveries. Initial deliveries were estimated to be contracted on a 1:7300 rate of take basis. Imperial illustrated the uncertainty of the forecast by showing a range of estimates of deliverability which reflected the Dempster lateral construction schedule, development rates, production performance and exploration success. Its deliverability forecast started at 261 petajoules in 1992, attained a level of 571 petajoules by 1994 and then remained constant to the year 2000.

For the Arctic Islands, Imperial forecast production would start in 1986 through the Arctic Pilot Project. On the assumption that the Polar Pipeline would be completed after the Alaska gas pipeline and Dempster lateral, Imperial forecast gas deliveries through the Polar line to commence in 1996. Imperial illustrated the uncertainty of the forecasts by presenting a range of deliverability which reflected the Arctic Pilot Project timing or expansion, exploration success and uncertainties associated with the Polar Pipeline. For the Arctic Islands, Imperial's forecast of gas deliverability commenced with the APP at 48 petajoules in 1986, increased to 96 petajoules in 1987 and was maintained at that level until 1995. In 1996, with the Polar Pipeline in place, the deliverability increased to 591 petajoules, reaching 1 170 petajoules by the year 2000.

Imperial predicted that production from Sable Island would start in 1988. A range of deliverability was illustrated to reflect uncertainty about timing and level of future gas production. Production was forecast to commence at 96 petajoules and increase to 193 petajoules by 2000.

NOVA was confident that, under its base case assumptions, frontier supply could be developed and brought to market as required. The only frontier supply forecast actually considered by NOVA was with respect to the future deliverability test where it included 90+petajoules per year of gas from the Arctic Pilot Project commencing in 1986 in its forecast of future deliverability.

Ontario considered two potential supply systems for the Arctic Islands and the Mackenzie Delta-Beaufort Sea area. A pilot LNG scheme from the Arctic Islands was projected to commence operation in 1986 with an initial capacity of 38 petajoules, increasing to 77 petajoules in 1986. A major pipeline connection to the Delta-Beaufort and Arctic areas was assumed to be in operation by 1990 with an initial capacity of 347 petajoules, building up to 905 petajoules by 1992. Ontario forecast additional capacity by 1997 with a projected capacity of 1 348 petajoules by the year 2000. The forecasts assumed that there would be a resolution of technological, environmental and regulatory matters and the necessary marketing and financing arrangements would be made.

Only minor quantities of natural gas were forecast to be produced from the offshore areas of Nova Scotia or Labrador. Initial quantities of 48 petajoules were forecast to be produced by 1989, increasing to 144 petajoules a year by 1999.

The uncertainties raised by the NEP would cause sponsors of Arctic projects to reassess their circumstances. Some proposals might be delayed or deferred indefinitely. The East coast operations might proceed as forecast because of the advantages of supply in that market area.

Panarctic's supply forecast for the Arctic Islands was based on the Arctic Pilot and the Polar Gas projects commencing operation by 1985 and 1990 respectively. Its forecast, based on a most likely scenario, showed the average daily gas volumes to be delivered by the producers to the transportation systems. For the Arctic Pilot Project, production commenced in 1985 at 3.82 million cubic metres per day, increased to 7.65 million cubic metres per day in 1986 and remained at this level to the year 2000. The Polar Gas project supply commenced at 38.24 million cubic metres per day in 1990, increased to 41.56 million cubic metres per day in 1991 and continued at this level until the end of the forecast period.

Panarctic expressed concern that while the NEP would be a direct benefit to it, some of its shareholders and joint interest owners would be adversely affected and, as a result, exploration could be reduced or stopped.

Due to the uncertain timing of new markets, Petro-Canada had not prepared specific forecasts. It did estimate, however, that potential established frontier reserves could be producing prior to 1990 with production rates as high as 1 000 to 2 000 petajoules per year during the 1990s. It forecast the Drake Point field in the Arctic Islands and the Sable Island area each producing 96 petajoules per year in 1985 and 1988 respectively.

Shell recognized that the Canadian frontier regions had potential for significant natural gas reserves. It claimed, however, that the economic attractiveness of various portions of these regions were clouded by factors such as high costs, remoteness, and difficult operating conditions, as well as jurisdictional uncertainties and certain aspects of pending federal legislation which would result in considerable uncertainty as to the rate at which exploration, discovery and development would proceed.

Despite potential problems with jurisdictional disputes, gas pricing, and the need for additional proved-up reserves, Shell was of the opinion that sufficient reserves might be found in the Sable Island area to support a gas delivery system by the mid 1980s.

Texaco assumed that there would be no production from the Arctic Islands during the forecast period but did forecast production from Sable Island commencing about 1987, with 153.7 petajoules being produced in 1990, increasing to 192.1 petajoules by 1995 and continuing at this level to the year 2000.

Because of the NEP, Texaco indicated that it would only proceed with its very low risk frontier projects such as Sable Island.

Views of the Board

The Board considers that a high degree of uncertainty is associated with various frontier developments at this time. These developments range from delineation of reserves to transportation systems. In view of the uncertainty, the Board has not included frontier reserves as a component of available supply in its base case for this inquiry. For illustrative purposes only, the manner in which supply availability would be increased by the addition of deliverability from certain frontier areas is illustrated in Figure 16-15.

For the Mackenzie Delta area, since there has been essentially no drilling activity since the Board's June 1977 Report "Reasons for Decision — Northern Pipelines", the Board continues to rely on its estimate of deliverabillty contained in that report. Based on its estimate of 5.6 exajoules of established reserves, the Board estimates that annual deliveries from the Delta of some 280 petajoules using a rate of take of 1:7300, will commence in 1987. However, until there are assurances that transportation facilities will be built, the Board does not believe that Mackenzie Delta deliverability should be included in projections of gas supply from established reserves or reserves additions.

In the Beaufort Sea area, the Board believes that at present, the gas found cannot be quantified and more drilling will be required to determine if, in fact, commercially producible quantities do exist. In view of this uncertainty, it would not appear appropriate to develop even illustrative gas deliverability for the forecast period in this report.

The Board made no attempt to develop a deliverability schedule for the Arctic Islands because of uncertainties associated with transportation systems. However, since the Arctic Pilot Project Application is before the Board, a twenty-year production pro-

file of quantities applied for, 103 petajoules per year (including fuel requirements) from the Borden Island main pool in the Drake Point field, is included as an illustrative component of supply beginning in 1985.

In considering the Sable Island area, the Board is of the view that companies will continue operations until a threshold volume of gas is developed. To show the effect of potential supply from this area, the Board assumed a required threshold of 3.4 exajoules. Deliveries are illustrated to commence around 1988 at 170 petajoules annually based on a rate of take of 1:7300.

There are several single well discoveries off the coast of Labrador, however, the Board is of the opinion that there is not sufficient information to allow speculation on the future economic viability of a transportation scheme for moving gas to markets. Hence, no supply from this area is illustrated.

11.4 Other Supply Sources

11.4.1 *Very Low Permeability Reservoirs*

Introduction

Natural gas from very low permeability reservoirs is variously referred to as gas from tight formations or tight reservoirs, from low porosity (or permeability) reservoirs, or unconventional gas.

This section deals only with very low permeability reservoirs occurring in rocks of Mesozoic age in the Deep Basin, a region immediately east of the Rocky Mountain foothills belt, extending some 450 kilometres from about 53° north latitude in Alberta to about 56° in British Columbia. The Mesozoic section is generally of low permeability, but contains gas producible by conventional means as well as that in very low permeability reservoirs requiring special stimulation before commercial rates of production can be expected.

Views of Submittors

The consensus among Submittors, with the exception of Canadian Hunter and Amoco, appeared to be that very limited if any established reserves could be assigned to the very low permeability reservoirs in the Deep Basin.

Canadian Hunter, at the Board's 1978 supply/demand hearing, concluded that at various levels of price and technology, 12.5 trillion cubic metres of gas, both conventional and unconventional, could ultimately be recovered from the Deep Basin, and that 1.4 trillion cubic metres were recoverable at the 1978 level of economics and technology. Canadian Hunter stated at the current inquiry that since 1978 it had drilled 95 wells in the Deep Basin and results supported its 1978 conclusions.

Amoco said a large volume of gas existed in the low permeability reservoirs of the Deep Basin and that a substantial amount of that gas was available at pre-NEP producer netbacks.

Dome was of the opinion that many of the tight reservoirs of the Deep Basin could be produced, but the economics were not too attractive. The company included only conventional reservoirs in its estimate of established reserves in the Deep Basin.

British Columbia did not include unconventional gas reserves for the portion of the Deep Basin within Northeastern British Columbia.

Ontario submitted that the very low permeability gas reservoirs in the Deep Basin would have only a small impact on the total gas supply and would not develop significant deliverability. It was concerned about the possible inclusion in supply estimates of large volumes of tight formation gas that could not, in a reasonable time, be put into the marketplace.

CPA included only a small volume (less than 14 billion cubic metres) of gas from tight formations in its established reserves estimate for the Deep Basin, but stated that this did not detract from the potential for future reserves from this source.

Imperial did not include gas from tight reservoirs in the Deep Basin in its forecast of reserves additions. It believed that new well completion technology and higher producer netbacks would be needed to achieve any large scale recovery. Imperial submitted a report on its tight sands research in which doubt was expressed as to the general applicability of massive hydraulic fracturing as a means of stimulating production from these reservoirs.

Studies by a consultant, which formed parts of the NOVA, TCPL, and Petro-Canada submissions, concluded that advances in technology or very significant changes in economics (a five-fold increase in producer netbacks) would be required to accurately quantify reserves and lead to economic development and production of tight formation gas from the Deep Basin. The consultant believed that it was premature to recognize gas reserves from these formations. From data which were available, the consultant concluded that, to date, no operator had been able to consistently obtain commercial production from zones with permeability less than 0.1 millidarcies. The consultant stated that only one large acid treatment had been a true success while the remainder of the treatments gave, at best, marginal improvement. The response to massive hydraulic fracturing had been less promising, with only one well even coming close to showing adequate post-stimulation performance to pay out the cost of the treatment. Gas prices would have to increase significantly and treatment costs come down before massive hydraulic fracturing would be applied on a large scale. The consultant placed a low probability on full scale development of very low permeability reservoirs before 1985, but expected that technological improvements and increases in gas prices would create a high probability of such development in the 1985-1990 period.

Norcen expected only limited gas volumes from very low permeability reservoirs during the forecast period. It did not include any of this gas in its supply/demand balance.

Views of the Board

The Board has not included any gas from the very low permeability formations of the Deep Basin in its estimates of established reserves as it does not believe this gas can be economically produced at this time.

The evidence suggests that there is a high degree of uncertainty surrounding the future exploitation of this resource. Because of the large volumes of gas potentially available to replace conventional supplies as the latter decline, the Board considers it of prime importance that projects be undertaken which will determine whether significant quantities of gas are in fact producible. Thus far, it appears the potential has been predicated largely on theoretical calculations. The Board would encourage producing companies to seek out ways to economically assess the commercial prospectiveness of Deep Basin very low permeability formations. Special arrangements may well be necessary if this is to be accomplished expeditiously.

11.4.2 Substitute Natural Gas

11.4.2.1 *From Coal*

Views of Submittors

Those Submittors who addressed this subject generally agreed that the commercial production of synthetic natural gas from coal was not likely to occur during the next two decades. This was based on the current and projected costs of coal gasification and on the reserves of natural gas which are estimated to exist. In addition, the oil sands and other hydrocarbon sources were forecast to come into play long before coal.

Views of the Board

The conversion of coal to synthetic natural gas which can then be economically transported in existing pipeline systems offers a potential means of meeting Canadian requirements for natural gas. However, the Board's assessment indicates that the cost of coal gasification projects makes synthetic natural gas from coal more costly than conventional natural gas. In addition, the lead time required to develop mines and suitable conversion processes severely detracts from the potential availability of synthetic natural gas from coal during the forecast period. Therefore, the Board expects that during the forecast period coal will not be used to produce synthetic natural gas for use as an energy source in Canada with the possible exception of pilot project facilities in the later years of this century.

11.4.2.2 *From Other Sources*

Views of Submittors

NOVA submitted that methane was generated in the process of coal formation and all coal deposits contain methane in varying concentrations. The Alberta resource was estimated to be about 50 billion cubic metres. The resource in the Springhill, Joggins-River Hebert, and Pictou areas of Nova Scotia was estimated to be about 1.3 billion cubic metres, of which it appears feasible to recover 680 million cubic metres. NOVA submitted that it had begun a pilot commercial project in the Pictou area. It estimated that some 250 wells might produce some 280 thousand cubic metres per day of methane by demethanation. It stated that the pilot project supply target might be reached as early as 1982-83 if the exploration program begun in late 1979 proved successful. The economic viability of the project would depend on the future price of natural gas and the development of a natural gas distribution grid in Nova Scotia.

Views of the Board

The Board finds that, although there may be some potential for coal-bed demethanation to contribute to Canada's natural gas supplies, with the inadequate development of the production technology, the lack of substantiated economic viability and the lack of a developed natural gas distribution grid in Nova Scotia, coal-bed demethanation is not likely to make a significant contribution to Canada's natural gas supply.

The Board believes that hog-fuels will be the major biomass fuel that will be used to produce substitute natural gas and that this gas will be consumed on-site.

CHAPTER 12
NATURAL GAS LIQUIDS SUPPLY

12.1 Introduction

Some 27 Submittors presented views on the supply of natural gas liquids (NGL) for one or more of the NGL supply categories suggested in the Board's Outline for Submissions.

Submittors were asked to comment separately on the supply of NGL from field plants processing gas from established oil and gas reservoirs, reprocessing plants, and reserves additions. For convenience, however, the views of Submittors on all these categories are discussed under Supply From Gas Plants.

12.2 Supply From Gas Plants

Views of Submittors

The views of Submittors on NGL supply from gas plants were detailed principally in forecasts for individual natural gas processing plants. Submittors provided detailed forecasts for about 75 percent of the 122 plants which the Board indicated it would review in detail. In addition, several Submittors supplied forecasts of total NGL supply from gas plants in Canada. These forecasts of ethane, propane, butanes and pentanes plus production are shown in Figures 12-1 through 12-4 respectively. The forecasts include production from established reserves and from reserves additions, from both gas processing and reprocessing facilities.

British Columbia submitted estimates of remaining established reserves of propane, butanes and pentanes plus in the province of 1.5, 2.2 and 4.2 million cubic metres respectively. British Columbia also submitted estimates of future reserves additions of natural gas liquids in the province of 1.4, 2.4 and 4.1 million cubic metres for propane, butanes and pentanes plus respectively. These estimates were based on estimates of undiscovered gas reserves, with the further assumption that some 27 percent of these volumes would be processed to recover liquids in the Fort St. John plant. British Columbia also indicated that the recoveries of propane, butanes and pentanes plus experienced during the 1976 to 1978 period were assumed to continue in the future.

CPA estimated the initial established reserves of liquefied petroleum gases (LPG) and pentanes plus as of 31 December 1979, to be 213 and 184 million cubic metres respectively. From data submitted by CPA, remaining established reserves of LPG and pentanes plus were calculated to be 114 and 84 million cubic metres respectively. CPA's estimates of LPG and pentanes plus reserves additions from both appreciation and future discoveries were 162 and 140 million cubic metres respectively.

CPA's combined forecast of ethane, propane and butanes production showed an increase from 39 thousand cubic metres per day in 1980 to 44 thousand cubic metres per day in 1982. Production then declined to 42 thousand cubic metres per day in 1983 followed by an increase to 47 thousand cubic metres per day in 1984. After 1984, production declined to reach 36 thousand cubic metres per day in 1990.

CPA believed that the impact of the NEP on NGL production would be similar to that on natural gas.

Dome's NGL supply was forecast in the context of Dome's forecasts of crude oil and natural gas supply capability without considering market constraints on supply.

Dome's ethane supply forecast, based on production from seven major plants, assumed additional deep cut facilities would be installed at Cochrane in 1983, a new Empress plant would be constructed to handle incremental volumes in 1984, existing gas composition would remain constant, and Steelman ethane recovery would commence in 1981.

The field plant propane and butanes forecasts were estimated by declining 1979 production at reasonable rates to reflect ultimate reserves. The propane and butanes forecasts were said to be net of injection requirements for miscible floods. Dome assumed that the Rainbow miscible flood would terminate in 1983 and the South Swan Hills flood would terminate in 1984. Dome's field plant pentanes plus forecast was taken from the NEB "Crude Oil Supply and Requirements", September 1978 Report.

To generate forecasts of flowing gas, both in volume and location, for reprocessing plant forecasts, Dome assumed that export approvals would be such that, for 1986 and beyond, gas production would be about 95 to 96 percent of total capability. The A & S licence was extended at today's level so that the Cochrane plant was kept at capacity.

Dome's forecasts of pentanes plus, butanes and propane supply from trend gas were separated into supply from solution gas and from non-solution gas. To help forecast the NGL content of trend gas Dome analyzed historical field plant NGL to gas ratios for nine areas and nine zones in Alberta.

Dome calculated future NGL to gas ratios based on historical field plant NGL to gas ratios for non-solution gas to be 60.3, 21.5, and 16.9 cubic metres per million cubic metres of non-solution gas for pentanes plus, propane and butanes respectively.

Dome calculated future NGL to solution gas ratios to be 360, 236 and 199 cubic metres per million cubic metres of solution gas for propane, butanes and pentanes plus. In addition, Dome determined that 106 cubic metres per cubic metre of crude oil represented an average solution gas to oil ratio.

Dome stated that imposition of the new federal tax on LPG production would not change the ratio of gas liquids production to gas and oil production but that there would be an impact on the future level of oil production and the future level of gas production. Dome stated that even with the tax in place, it could not

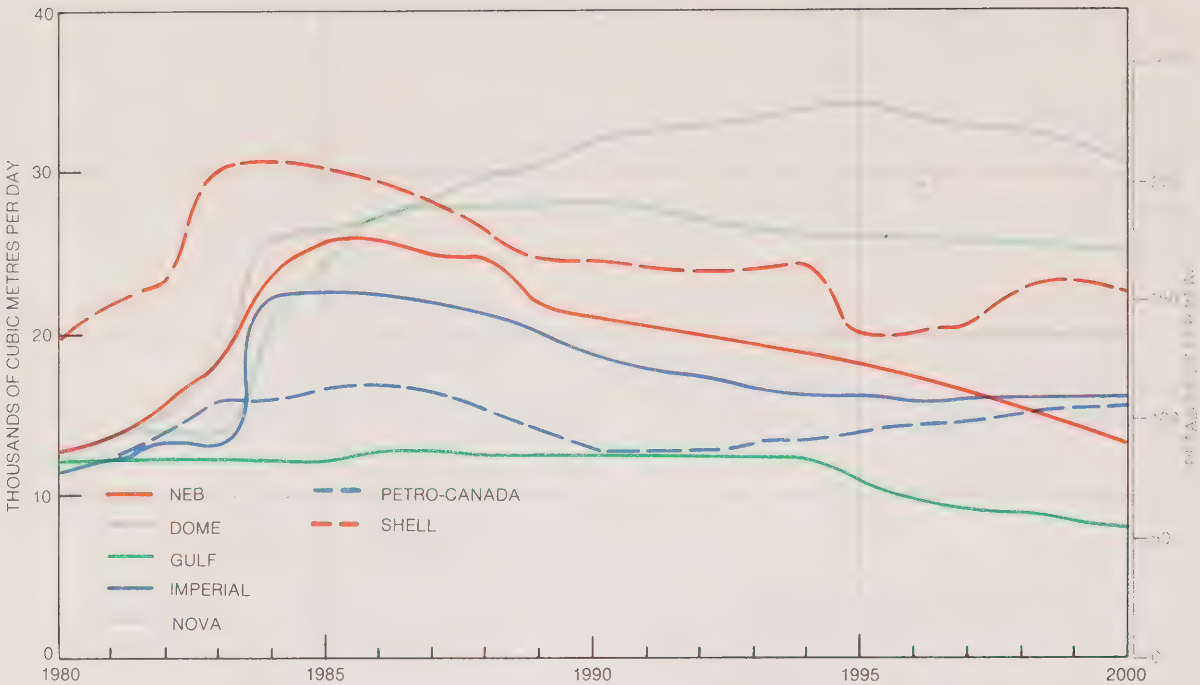

Figure 12-1 Ethane Supply from Gas Plants
Comparison of Forecasts

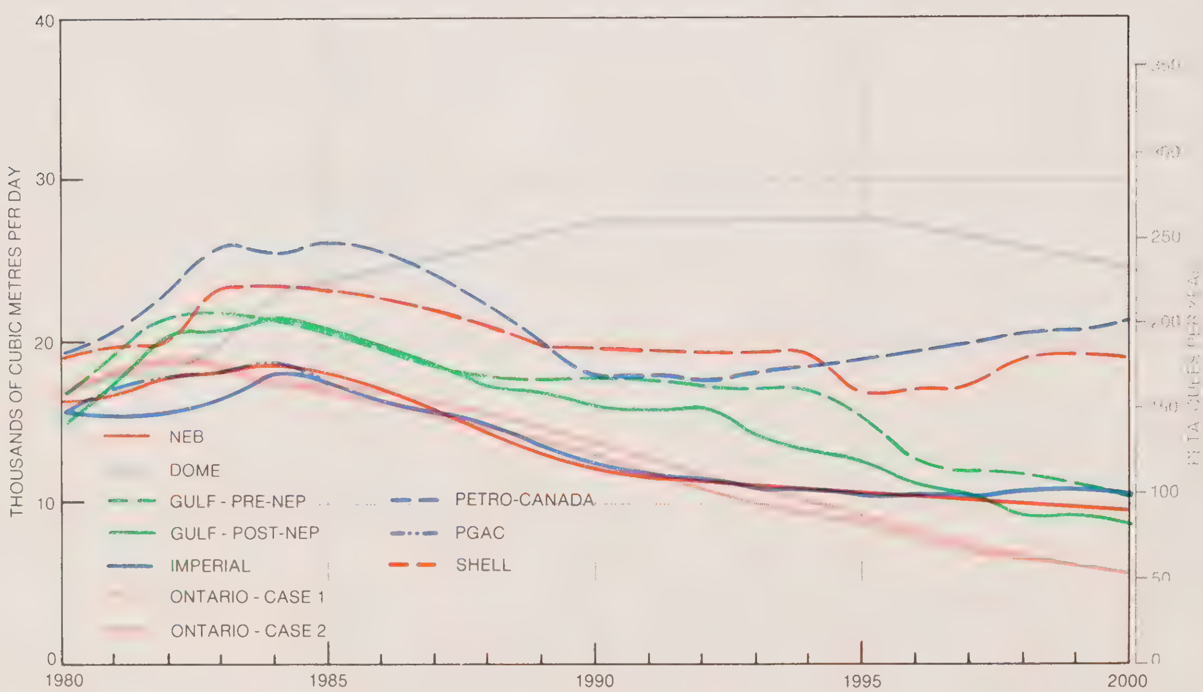

Figure 12-2 Propane Supply from Gas Plants
Comparison of Forecasts

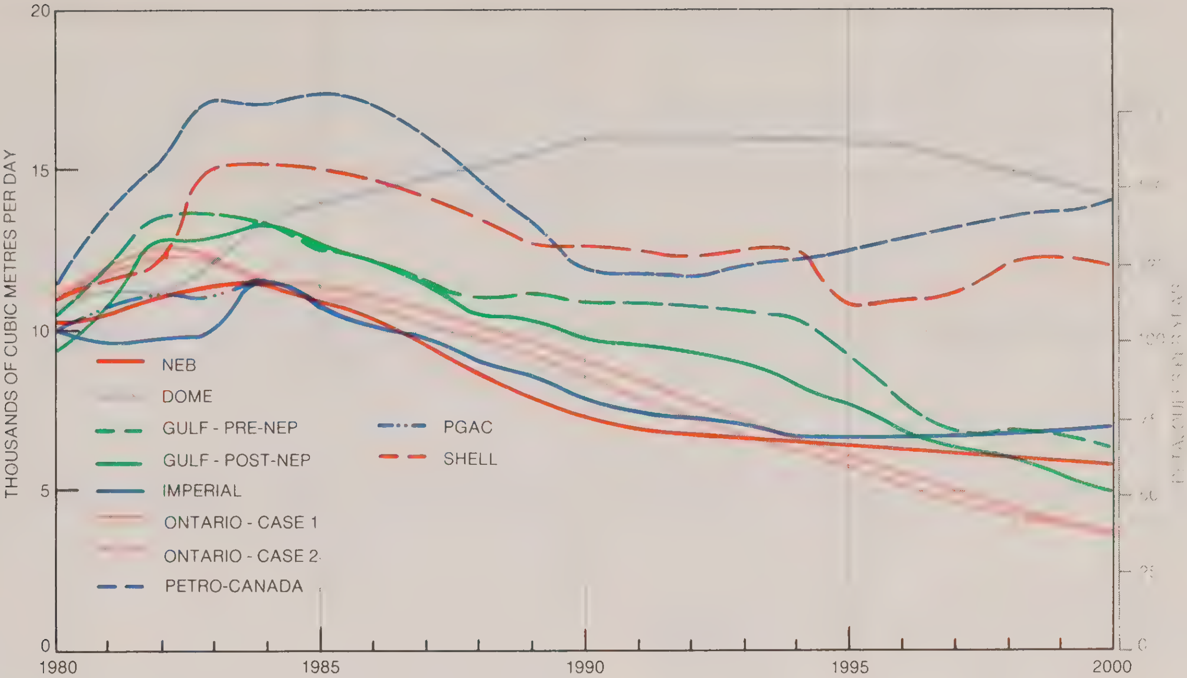

Figure 12-3 Butanes Supply from Gas Plants
Comparison of Forecasts

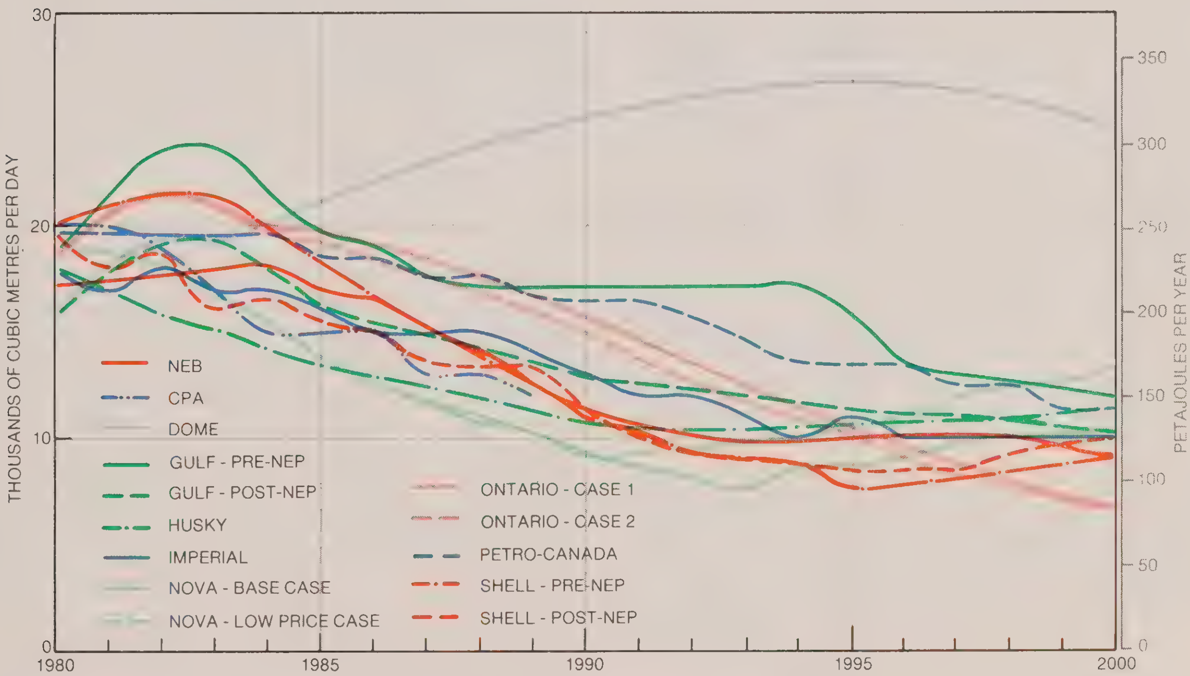

Figure 12-4 Pentanes Plus Supply from Gas Plants
Comparison of Forecasts

foresee existing facilities operating at less than their efficient capacity.

Dome pointed out that the establishment of an LNG market could have some impact on the future supply of NGL in British Columbia, since additional gas sales would increase the throughput of the Westcoast line sufficiently to warrant the extraction of natural gas liquids.

In preparing supply forecasts of ethane, propane and butanes resulting from the production of natural gas, Gulf assumed that liquid yields would decline with time. However, this would be offset in the next few years by increased gas production as a result of increased exports.

In discussing declining liquid yields over time, Gulf stated that the historical liquid recovery has mainly been from Nisku and Leduc gas sources in the central plains, and shallower foothills areas of Alberta which have been generally rich in liquids. Gulf pointed out that there was a movement to deeper horizons where there is a tendency to lower gas liquid content.

Gulf's ethane forecast was based on estimated production for each of the plants currently producing ethane and no additional field extraction of ethane was assumed.

Gulf submitted a pre-NEP forecast of pentanes plus production based on projected natural gas production and on a natural gas richness forecast. This forecast showed increased production for the next few years as a result of increased natural gas export demand and increased production of gas from pools rich in liquids. Gulf also submitted a post-NEP forecast of pentanes plus production based on its revised forecast of natural gas production and on the forecast of liquid yield factors.

Imperial's forecasts of ethane, propane, butanes and pentanes plus production were based on natural gas production required to meet domestic demand and currently authorized exports, and a crude oil productive capacity forecast for the Southern Basin.

Imperial's forecast of ethane production assumed that additional ethane volumes would become available in 1984 through the expansion of existing straddle plants and the development of deeper cut facilities at existing and new plants, if an economic incentive to recover this product continued.

Imperial stated that production of propane and butanes from established reserves would increase in the near term with the development of unconnected natural gas reserves to meet natural gas demand and increased recovery of these products resulting from additional ethane recovery facilities. In the longer term Imperial forecast that production volumes would decrease with decreasing volumes of associated gas, the lower liquid content of the currently unconnected natural gas reserves, and a reduction in liquid recoveries from existing cycling projects. Imperial also assumed that as additions from new discoveries and reserves appreciation were developed, recovery levels from new plants would be similar to historical recoveries from existing plants processing gas from the same geological formation. In Alberta, Imperial used yields of 72, 44 and 30 cubic metres of liquid per million cubic metres of raw gas for ethane, propane and butanes respectively in preparing its liquids production forecast from new discoveries. Production of ethane, propane and butanes from appreciation was based on yields of 54, 39 and 22 cubic metres of liquid per million cubic metres of raw gas, respectively. In British Columbia, Imperial assumed liquid yields from new discoveries of six and seven cubic metres of liquid per million cubic metres of raw gas for propane and butanes respectively.

Imperial submitted in its post-NEP submission that although Esso Resources had not forecast natural gas liquids production as a function of proposals in the NEP, reductions in crude oil and natural gas production rates would result in somewhat lower levels of natural gas liquids production.

NOVA's forecast of ethane availability from the processing of natural gas was based on a particular gas flow case analyzed by Alberta Gas Ethylene. This gas flow case assumed larger natural gas flows than those presented in NOVA's base case for natural gas supply, because it included the renewal of currently existing export licences and permits.

NOVA prepared forecasts of pentanes plus producibility from existing reserves for over one hundred gas processing plants in Alberta. The forecasts were prepared taking into account the pentanes plus content of several thousand raw gas streams in Alberta together with the appropriate pentanes plus recovery efficiencies at each plant.

Production of pentanes plus from crude oil reserves growth was forecast assuming that the historical average recovery of 0.025 cubic metres of pentanes plus per cubic metre of crude oil would continue. NOVA's forecast of tertiary light and medium crude oil production was used in estimating production rates for future tertiary recovery projects in conjunction with estimates prepared by AERCB for new discoveries and reserves appreciation. These combined assumptions resulted in forecast pentanes plus production from crude oil reserves growth rising to an estimated 953 cubic metres per day by 1990 and 1 240 cubic metres per day by 1995.

NOVA forecast two cases of pentanes plus production from trend gas sources, a base case and a low case, each with its own assumption as to natural gas pricing. The forecast indicated that trend gas supplies would not be required until 1993 in the base case and 1989 in the low case. An estimate of the pentanes plus content of trend gas was prepared using some 6 000 gas analyses in conjunction with estimates of undiscovered gas reserves in the province of Alberta. The available gas analyses were divided into five geological groupings and weighted according to the estimated undiscovered gas reserves potential for each grouping. The results of these calculations indicated a pentanes plus content for undiscovered gas reserves in Alberta in the range of 36 to 47 cubic metres per million cubic metres of pipeline gas. NOVA adopted a value of 45 cubic metres per million cubic metres of pipeline gas for purposes of its submission. The forecast of pentanes plus production from British Columbia was said to be proportional to gas deliveries from that province. Saskatchewan production was forecast

assuming pentanes plus production would be proportional to light and medium crude oil production.

Ontario submitted estimates of currently established reserves in conventional areas of 124 million cubic metres of pentanes plus, 71 million cubic metres of butanes and 108 million cubic metres of propane in Alberta and four, two and two million cubic metres for pentanes plus, butanes, and propane respectively in British Columbia.

Ontario submitted two gas plant supply forecasts for each of pentanes plus, butanes and propane. The first supply case was based on an effective rate of take for reserves additions of 1:6000 while the second case was based on an effective rate of take of 1:7680. Both NGL supply cases were unrestricted by demand.

Petro-Canada submitted forecasts of ethane, propane, and butanes production, indicating that these commodities were co-products or by-products derived from crude oil and natural gas streams. Therefore, the supply of these commodities depended on the demand for processed natural gas and petroleum products.

Petro-Canada forecast recoveries of total propane and butanes in field and natural gas plants of 0.000 127 5 cubic metres of LPG per cubic metre of gas, based on the 1976 to 1979 average. The liquids recovered were assumed to be 60 percent propane and 40 percent butanes.

Petro-Canada indicated that its forecast of productive capacity for pentanes plus suggested that production could be maintained at current levels for the next six years. This forecast assumed that the pentanes plus content of the gas stream would not decline precipitously over the forecast period and that total gas production levels would increase to reflect growth in Canadian gas requirements and in requirements for exports. After 1986, total gas production was forecast to decline as authorized exports declined. In addition, Petro-Canada's forecast assumed that the pentanes plus content of natural gas reserves additions was 67.8 cubic metres per million cubic metres of gas.

PGAC submitted forecasts of propane and butanes supply from gas plants. The gas plant forecasts were compiled on a plant by plant basis following a survey of gas plant operators. Operators supplied forecasts of LPG extraction from gas streams currently being processed and from those expected to be processed over the forecast period.

PGAC indicated that a 15 percent curtailment of oil production would probably result in about a three percent reduction in the production of LPG. PGAC indicated that only about 20 percent of the LPG forecast in its study would be affected by a decrease in crude oil production.

Shell submitted estimates of year-end 1979 Alberta reserves of 128, 106 and 71.3 million cubic metres for ethane, propane and butanes respectively. It also submitted year-end 1979 reserves estimates of 1.5 and 2.2 million cubic metres respectively for propane and butanes in British Columbia.

Shell estimated reserves additions for NGL in Alberta, over the period 1980-2000, of 136, 85 and 57 million cubic metres for ethane, propane and butanes respectively. Over the same period, for British Columbia, Shell estimated reserves additions of 3.0 and 5.0 million cubic metres for propane and butanes respectively.

Shell's forecasts of ethane, propane and butanes supply from gas plants were based on its gas supply/demand balances for Alberta and British Columbia. The Alberta demand included an incremental wedge of 622 petajoules per year of natural gas exports during the period 1983-1994. Shell stated that the early years of the propane and butanes forecasts were adjusted to allow for soft export markets in 1980 and production from gas fields with above average liquid to gas ratios.

Shell's forecasts of propane and butanes production in Alberta assumed that the ratio of remaining established reserves of each liquid to remaining established reserves of marketable natural gas would remain constant.

Shell predicted ethane production in a manner similar to the propane and butanes forecasts. However, Shell's ethane production forecast was one of maximum potential availability as opposed to a forecast of actual plant production. The portion of the available ethane that would actually be recovered would depend on the construction of additional extraction facilities.

Shell's starting point for the pentanes plus production forecast from gas plants was a CPA operator survey of 47 of the larger plants which accounted for 91.1 percent of the actual pentanes plus production in 1979.

Shell prepared a forecast of pentanes plus to gas production ratios which recognized the significant historical decline in Alberta's pentanes plus to gas production ratios and the estimated over-life pentanes plus to gas ratio for remaining established reserves. This forecast showed a decline from 87 to 23 cubic metres of pentanes plus per million cubic metres of gas over the forecast period for production from established reserves. Shell assumed that the same forecast would be applicable to production from the appreciation of existing gas reserves. For new gas discoveries, Shell chose a value of 30 cubic metres of pentanes plus per million cubic metres of gas which represented the average pentanes plus content of gas discoveries in Alberta over the last 10 to 15 years.

Shell indicated that similar steps were taken to develop a full deliverability forecast of pentanes plus production in British Columbia.

Shell submitted a new forecast of pentanes plus production in a supplemental post-NEP submission. This forecast was prepared by determining for each year, the ratio of its revised gas production forecast to the values in its September submission, and then applying these ratios to the original pentanes plus production forecast.

Views of the Board

Based on the evidence submitted and the Board's own detailed studies, the Board has prepared forecasts of ethane, propane,

butanes and pentanes plus production from gas plants. These forecasts are summarized in Tables 12-1 to 12-4 respectively. Detailed plant-by-plant forecasts of propane and butanes, and pentanes plus production are provided in Appendices Q and M respectively.

The Board's forecasts of NGL production are based on the gas deliverability in the Future Deliverability Test (tracking case) with some adjustment in the early years to allow for expected, lower than licensed, exports. The forecasts include production of NGL from established reserves and reserves additions of natural gas at both gas processing and reprocessing plants. Production of NGL expected to be used in EOR projects is also included in the forecasts.

Production from existing gas processing plants was forecast on a pool-by-pool basis with the pools grouped according to the gas plant in which the gas is processed. Changes in NGL yields with depletion of a reservoir, gas cycling schemes, and NGL recovery efficiencies in each plant are accounted for in the model.

Production from reprocessing plants is based on the assumption that additional deep cut facilities will be installed at Cochrane in mid-1983 and at both Empress plants in mid-1984. It is further assumed that the Empress facilities will be enlarged in 1984 to process additional quantities of natural gas. These expansions, along with the installation of deep cut facilities at field processing plants in Alberta and Saskatchewan, are particularly significant in the Board's forecast of ethane production, which from 1981 to 1985 is forecast to approximately double. No production from a reprocessing plant in British Columbia has been included, although the Board recognizes the possibility of a plant being constructed in the future.

For production of propane, butanes and pentanes plus from reserves additions of natural gas, the Board's forecasts are based on yields of 45, 27 and 45 cubic metres per million cubic metres of natural gas production, respectively. These yields are lower than current average NGL yields and reflect historical trends which show that, on average, recent gas discoveries have contained less NGL. The short-term increase in NGL production reflects expected increases in natural gas production and assumed expansions of straddle plant facilities. After 1984, reduced gas exports along with a decrease in the NGL content of produced gas, results in a decline in the forecast production of NGL.

Table 12-1

NEB FORECAST OF ETHANE PRODUCTION
($10^3m^3/d$)

	Total[1]
1981	13.9
1982	16.0
1983	18.6
1984	23.9
1985	26.1
1990	21.4
1995	18.4
2000	13.5

[1] Gas Plants only.

Table 12-2

NEB FORECAST OF PROPANE PRODUCTION
($10^3m^3/d$)

	Gas Plants	Refineries	Total
1981	16.6	3.8	20.4
1982	17.7	3.9	21.6
1983	18.1	3.9	22.0
1984	18.5	3.9	22.4
1985	17.9	3.9	21.8
1990	12.2	4.0	16.2
1995	10.6	4.2	14.8
2000	9.6	4.4	14.0

Table 12-3

NEB FORECAST OF BUTANES PRODUCTION
($10^3m^3/d$)

	Gas Plants	Refineries	Total
1981	10.4	2.4	12.8
1982	10.9	2.4	13.3
1983	11.2	2.5	13.7
1984	11.3	2.5	13.8
1985	10.9	2.5	13.4
1990	7.3	2.7	10.0
1995	6.4	2.8	9.2
2000	5.8	3.0	8.8

Table 12-4

NEB FORECAST OF PENTANES PLUS PRODUCTION
($10^3m^3/d$)

	Total[1]
1981	17.3
1982	17.7
1983	17.9
1984	18.1
1985	17.0
1990	11.2
1995	9.9
2000	9.0

[1]Gas Plants only.

The decrease in the average NGL content of produced gas is attributed to a reduction in the production of solution gas, the termination of cycling schemes, the reduction in the recovery of liquids from older pools as reservoir pressures decline, and the forecast lower NGL yields associated with reserves additions of natural gas.

Remaining established reserves of propane, butanes and pentanes plus are estimated by the Board to be 62, 45 and 86 million cubic metres, respectively. These estimates are based on the forecast production of NGL from the processing of established gas reserves at field processing plants, and do not include NGL which is forecast to be produced at gas reprocessing facilities.

12.3 Supply from Refineries

Views of Submittors

The views of Submittors on this source of NGL supply were generally presented as forecasts of total propane and butanes supply from refineries in Canada. These forecasts are shown in Figures 12-5 and 12-6 respectively.

Dome supplied forecasts of both propane and butanes production from refineries and noted that in general refineries were net suppliers of propane and net users of butanes.

Dome submitted that there were several Canadian refining industry trends developing which would alter refiners net LPG positions in the future. The more significant of these were the increasing percentage of the synthetic crude component in the overall crude mix available to refiners, the decreasing ratio of motor gasoline to distillate required by the marketplace, the increased pressure in the marketplace to improve gasoline quality, the major regional growth shift away from central Canada, and a very tight crude oil supply position with increasing energy prices and pressures to limit product exports.

Dome stated that historically refineries have recovered a very high percentage of butanes production primarily because of their own large internal demands. A recovery of about 95 percent was expected to continue during the forecast period and improve in some regions. Dome's forecast of refinery butanes supply shown in Figure 12-6 was based on the total production of butanes within Canadian refineries and included production used internally in refineries for blending, alkylation and fuel.

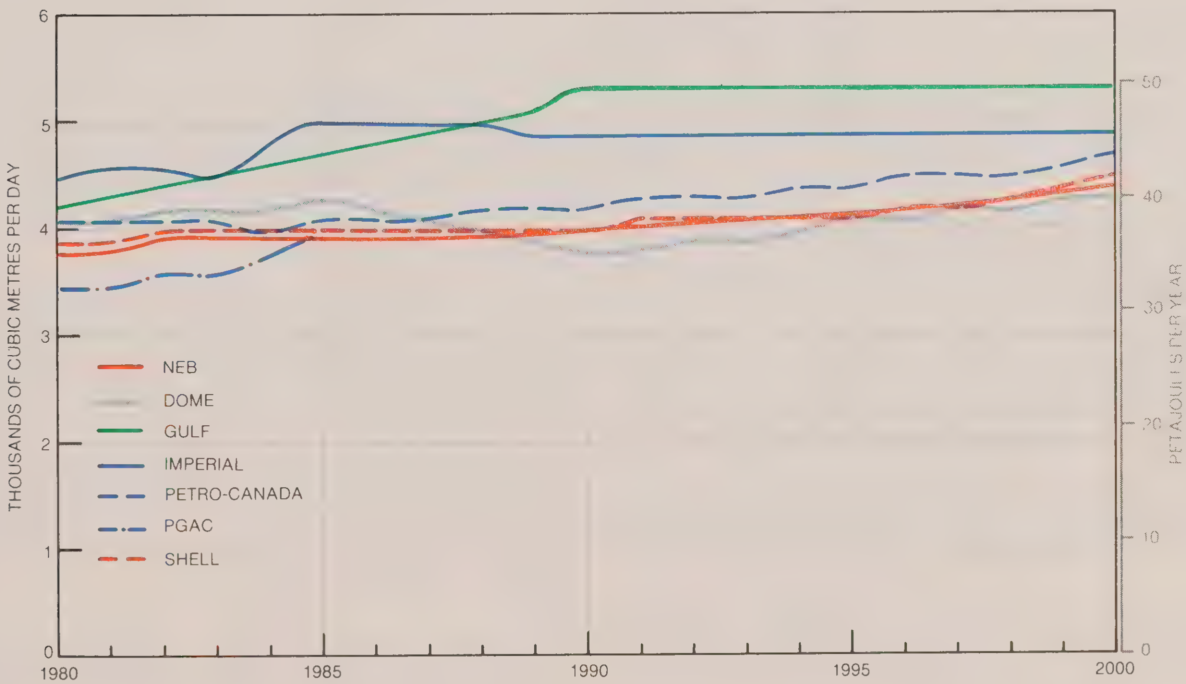

Figure 12-5 Propane Supply from Refineries
Comparison of Forecasts

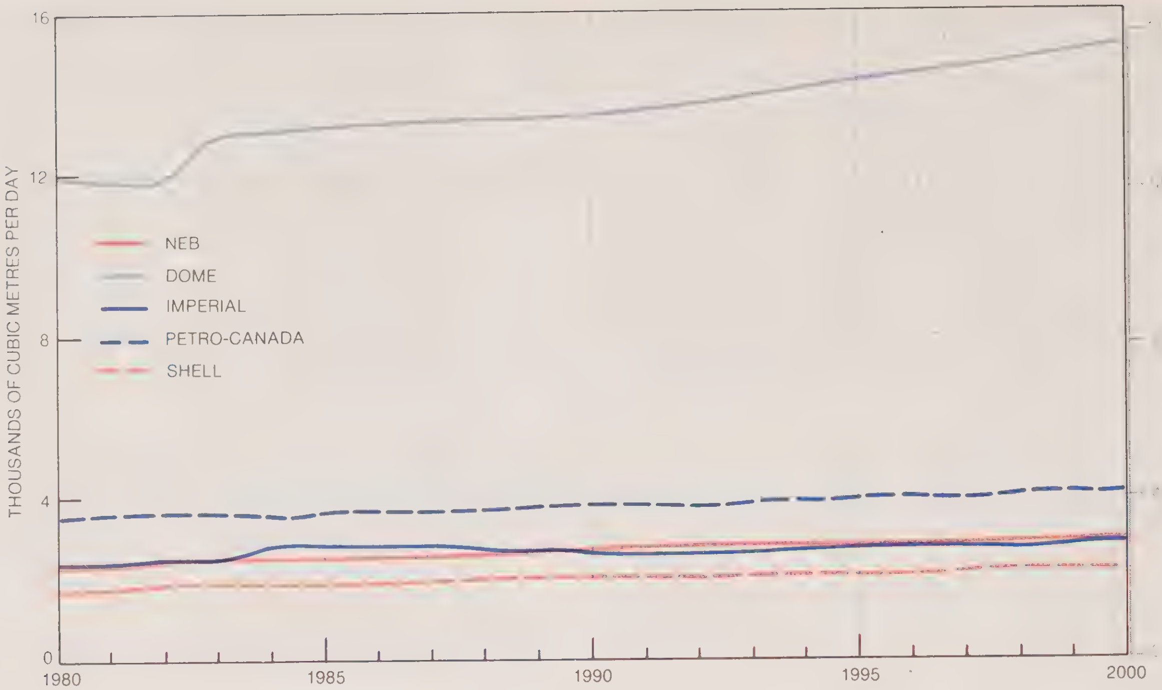

Figure 12-6 Butanes Supply from Refineries
Comparison of Forecasts

Gulf's forecast of propane supply from refineries was based on growth from existing refinery operations of 2.3 percent per year to 1990.

Imperial's forecast of natural gas liquids supply from refineries was based on expected use of existing refining capacity plus announced expansions.

Imperial stated that as refinery feedstocks would trend to heavier crude oils, higher severity of processing was anticipated. Imperial indicated that it varied liquids yields based on historical experience and with anticipated crude oil feedstock types.

Petro-Canada forecast recovery factors for propane and butanes to be 13.3 and 11.9 cubic metres per thousand cubic metres of crude oil respectively.

The forecast of propane production submitted by PGAC was compiled on a regional basis and was said to be based on a consensus opinion of future trends and a few specific likely future changes.

Shell forecast the current ratio of LPG output to total refinery runs would be maintained throughout the forecast period.

Texaco indicated that the upgrading of residual fuel oil in Canadian refineries would provide an incremental 0.7 cubic metres of LPG for each 100 cubic metres of crude oil processed.

Views of the Board

The Board's forecasts of propane and butanes production from refineries are summarized in Tables 12-2 and 12-3 and are detailed by region in Appendix R. The forecasts are based on the Board's middle case forecast of Canadian demand for refined crude oil products and refinery feedstock requirements.

The Board assumed that propane and butanes yields, expressed as a function of refinery crude throughputs, would increase slightly during the first half of the forecast period as refinery configurations are adjusted to meet the required product slate, reduce product exports, and improve the quality of gasoline.

In the Atlantic Region, Québec and Ontario, the production of propane and butanes from refineries is forecast to remain relatively constant with increases in production due to higher yields generally offsetting decreases in production resulting from lower crude throughputs. However, in the Prairies and British Columbia, expected growth in crude oil refining combined with

increased yields, results in about a 50 percent increase in the supply of propane and butanes by the year 2000.

12.4 Supply from Synthetic Crude Oil Plants

Views of Submittors

Gulf assumed propane production of 0.95 thousand cubic metres per day commencing in 1985, 0.48 thousand cubic metres per day commencing in 1988 and 0.48 thousand cubic metres per day commencing in 1989 from the Syncrude, Alsands and Cold Lake projects respectively.

With regard to the recovery of liquids from synthetic crude oil plants, Imperial submitted that preliminary work indicated that supplies of ethane and propane could be increased by about 3.2 to 3.6 thousand cubic metres per day. However, the feedstock for this project would require 1.9 thousand cubic metres per day of field butanes. Imperial did not include production of natural gas liquids from synthetic crude oil plants in its NGL production forecast.

NOVA provided a forecast of ethane supply from the processing of Alberta produced crude and synthetic oils based on the recovery of ethane from off-gas streams occurring at current and forecast Alberta synthetic oil plants and current Alberta refineries. This forecast showed ethane production increasing from 1 032 cubic metres per day in 1984 to 6 529 cubic metres per day by the year 2000.

Shell submitted that all NGL produced at oil sands plants would be consumed internally and therefore did not develop a forecast of production from this source.

Suncor indicated that the quantities of ethane, propane and butanes that could be recovered from its plant given suitable economic conditions would be 540, 584, and 94 cubic metres per day, respectively. Suncor, until recently, was studying the recovery of liquids from its plant, but has now curtailed this activity. Suncor did not see the recovery of liquids from its plant as something that would proceed within the immediate future.

Views of the Board

The Board recognizes that the processing of the various gas streams produced and used within synthetic crude oil plants could provide an additional source of NGL, principally ethane and propane. However, the Board does not forecast at this time that the necessary modifications will be made to existing synthetic crude oil plants to recover NGL and therefore, has not included supply from synthetic crude oil plants in its base NGL supply forecast.

12.5 Supply from Frontier Areas

Views of Submittors

Dome stated that the solution gas and the free gas that had been tested in Beaufort Sea wells to date was very lean, with a high methane content and a low potential for natural gas liquids production.

With regard to the Arctic Islands, Dome indicated that only a very minor amount of natural gas liquids was present in the Whitefish discovery.

Gulf assumed that although there may be some production of natural gas liquids from frontier natural gas production, it would be too small to transport to markets.

Mobil stated that tests of Scotian Shelf gas indicated about 67 to 78 cubic metres of liquids per million cubic metres of gas.

Imperial provided forecasts of ethane, propane and butanes production from the Mackenzie Delta and Sable Island areas, but assumed that recovery of liquids from Arctic Islands gas would not be economic.

Production of ethane, propane and butanes from the Mackenzie Delta was forecast to begin in 1992 at rates of 1.3, 0.7 and 0.4 thousand cubic metres per day respectively, increasing by 1994 to 2.8, 1.5 and 0.9 thousand cubic metres per day.

Production of propane and butanes from the Sable Island area was forecast to begin in 1988 at 0.4 and 0.3 thousand cubic metres per day respectively increasing by the year 2000 to 0.8 and 0.6 thousand cubic metres per day.

Panarctic estimated proved plus probable pentanes plus recoveries from the Roche Point, Char and Whitefish fields in the Arctic Islands to be 679, 469 and 3 639 thousand cubic metres respectively, for a total of 4 787 thousand cubic metres. Additional possible liquid recoveries from the same fields were estimated at 1 045 thousand cubic metres.

Petro-Canada indicated that its pentanes plus supply forecast did not include any volumes from frontier production. However, Petro-Canada did suggest that the pentanes plus content of Sable Island gas could be high.

Views of the Board

The Board's base case gas supply forecast assumes no production of natural gas from frontier areas and consequently no production of NGL from the frontiers has been included in the NGL production forecasts. However, based on the evidence presented and its own assessment, the Board believes that in the event of gas production from Sable Island or the Mackenzie Delta, there would be a potential for NGL recovery. Liquids produced in the Mackenzie Delta would require a transportation system to be put in place before they could be moved to market areas in Canada. The Board believes that Arctic Islands and Beaufort gas have a low potential for liquids recovery and if liquids were recovered from this gas, the quantities may be too small to warrant transportation to markets.

With regard to the possible production of natural gas associated with frontier oil production, the Board believes that any LPG associated with this gas would be reinjected along with the produced gas as part of a scheme to maintain reservoir pressure and enhance oil recovery. Any pentanes plus which is produced from this gas would be blended with, and included in, crude oil production.

CHAPTER 13
ELECTRICITY SUPPLY

13.1 Introduction

Because electricity, in general, is not stored, generated power follows the instantaneous load demand on electric power systems. The planning for installation of generating equipment is, therefore, governed by projections of demand. To ensure that the demand is supplied with adequate reliability, peak and energy reserves are maintained to cover equipment breakdown and scheduled maintenance. Installed generating capacity following sound utility practices thus may be some 10-25 percent larger than the peak load requirements.

Most major Canadian power utilities are provincially owned; the exceptions being utilities in Alberta and Prince Edward Island. Submissions concerning supply were received from eight provincial governments. Electric utilities in four of these provinces also made submissions. In order to complete a national picture, data available to the Board has been used for Prince Edward Island and Alberta.

13.2 Estimated Installed Capacity

Table 13-1 lists the installed capacity, by province and by type of generation, in 1980.* Table 13-2 lists energy generated in 1980,(1) again by province and type of generation.

Views of the Submittors

While several Submittors gave generation expansion plans up to 2000, supply data were omitted in other cases, so that a complete forecast of supply as seen by provinces and utilities cannot be presented. For those provinces submitting, the following supply programs were proposed:

Newfoundland and Labrador

Expansion anticipates development of Labrador hydro power, and transmission to the Island of Newfoundland.

Nova Scotia

The province expects to convert existing oil-fired generating units to coal, and all new capacity will use domestic coal.

New Brunswick

Generation expansion will continue as a mixed system using provincial resources of hydro, coal and peat, with a strong inclination to add further nuclear capacity. Conversion of existing oil-fired capacity to coal is under study. Energy export is important to the power system.

Québec

Further hydro resources will be developed; the future of nuclear power is indeterminate. Energy export is expected to be significant.

Québec's submission referred to the White Paper On Energy, made public in 1979.

Ontario

The bulk of new generation will be nuclear, with some incremental hydro and coal-based plants. Energy export is foreseen to be significant.

Table 13-1

INSTALLED NAMEPLATE CAPACITY (MW) BY PROVINCE AND TYPE
1980(1)

Province	Hydro	Coal	Oil(2)	Gas(2)	Nuclear	Other	Total
Newfoundland	6 444	—	744	—	—	—	7 188
Nova Scotia	363	639	1 032	4	—	—	2 038
Prince Edward Island	—	—	119	—	—	—	119
New Brunswick	893	85	1 784	—	—	23	2 785
Québec	19 095	—	1 096	4	266	16	20 477
Ontario	7 086	8 764	2 785	1 418	5 600	67	25 720
Manitoba	3 641	419	77	4	—	—	4 141
Saskatchewan	577	1 486	17	232	—	21	2 333
Alberta	718	3 269	76	1 663	—	75	5 801
British Columbia	8 995	—	411	1 154	—	206	10 766
Yukon	58	—	36	—	—		94
Northwest Territories	47	—	132	—	—		179
Canada Total	47 917	14 662	8 309	4 479	5 866	408	81 641

(1) Preliminary figures - "Electricity in Canada, update 1980" Energy, Mines and Resources Canada - Energy Sector: Presented at Canadian Electrical Association, Spring, 1981.
(2) Includes gas turbine and internal combustion capacity.

* Data from "Electricity in Canada, update 1980", publication prepared by the Department of Energy, Mines and Resources, for presentation to the Canadian Electrical Association, Spring 1981, updating "Electric Power in Canada," D.S.S. Cat. No. M13-24/80-7.

Table 13-2

ELECTRIC ENERGY (GW.h) GENERATED BY PROVINCE AND ENERGY SOURCE 1980[1]

Province	Hydro	Coal	Oil	Gas	Nuclear	Total	Export	Import	Total Prov. Supply
Newfoundland	44 860	—	1 398	—	—	46 258	37 829	—	8 429
Nova Scotia	903	1 508	4 452	—	—	6 863	227	173	6 809
Prince Edward Island	—	—	127	—	—	127	—	388	515
New Brunswick	2 666	457	6 160	—	—	9 283	4 432	3 956	8 807
Québec	97 560	—	242	5	—	97 807	17 536	37 880	118 151
Ontario	40 192	28 912	1 192	3 950	35 880	110 126	11 359	7 551	106 318
Manitoba	19 096	99	250	18	—	19 463	6 656	1 142	13 949
Saskatchewan	2 549	5 816	66	757	—	9 188	955	1 579	9 812
Alberta	1 699	16 855	22	4 816	—	23 392	385	107	23 114
British Columbia	40 860	—	935	1 539	—	43 334	3 454	2 822	42 702
Yukon	322	—	63	—	—	385	—	—	385
Northwest Territories	292	—	163	—	—	455	—	—	455
Canada Total	250 999	53 647	15 070	11 085	35 880	366 681	30 174[2]	2 940[3]	339 446

(1) Preliminary Figures - "Electricity in Canada, update 1980" Energy, Mines and Resources Canada - Energy Sector: Presented to Canadian Electrical Association, Spring, 1981.
(2) U.S. Export only.
(3) U.S. Import only.

Manitoba

Expansion is hydro-based, with provision for north-south diversity interchanges with United States utilities, and possible input to a Western Grid.

Saskatchewan

Generation expansion is coal-based, with development of hydro when economic.

British Columbia

The province will rely heavily on further hydro development; planning anticipates construction of two coal-fired plants.

Other Information

Prince Edward Island

Prince Edward Island did not make a submission. The utility supply system will presumably rely on the cable connection to the New Brunswick system, and on its own oil-fired capacity.

Alberta*

Base load will be supplied from domestic coal, supplemented by hydro where economic.

Views of the Board

The Board has developed a forecast of the generation expansion pattern in Canada. Table 13-3 shows estimated installed capacity, on a national basis, by type, at five-year intervals. National estimates for energy production are shown in Table 13-4, while estimates on a provincial basis are detailed in Appendix S. In addition, reserves and surplus as determined by the NEB's generation expansion model are shown in Figures 13-3, 13-4, 13-5, 13-6 and 13-7. Submissions have been taken into account where available. A comparison of expected energy sources in 2000 with those of 1980 in Figures 13-1 and 13-2, show significant trends in electricity supply, with decreasing shares of hydro and gas and oil, and increasing shares of coal and uranium to produce electricity.

* Submission to Alberta Energy Resources Conservation Board, entitled "Alberta Energy and Energy Resources Requirements 1981-2005" by
Electric Utility Planning council
Canadian Western Natural Gas Company Limited
Northwestern Utilities Limited
(January, 1981)

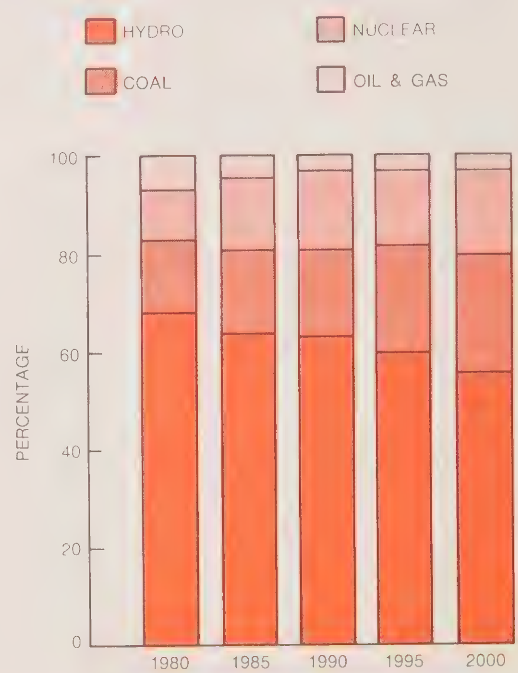

Figure 13-1 Electricity - Energy Generated by Fuel Type

Table 13-3

CHANGES IN PRIMARY SOURCES OF ELECTRIC ENERGY
1980-2000

		Year 1980	1985	1990	1995	2000
Estimated Primary Energy (PJ)		3 972	4 890	5 476	6 100	7 176
Estimated Electric Energy (TW.h)		367	452	506	564	663
Primary Energy	Hydro	68	64	63	60	56
Source[2][3] %	Coal	15	17	18	22	23
	Oil[1]	4	2	1	1	1
	Gas[1]	3	2	2	2	2
	Nuclear	10	15	16	15	17
Estimated % Exports		7	11	9	3	4

Source: NEB Internal Estimates
(1) Includes gas turbine, internal combustion capacity, and other peaking plants, as well as base load capacity.
(2) Other primary energy sources are estimated to contribute less than 1% to electricity supply.
(3) Percentages are based on Estimated Electric energy in TW.h, and include predicted energy exports.

Table 13-4

INSTALLED CAPACITY, RESERVES AND CHANGE IN PRIMARY SOURCES
FOR ELECTRICITY SUPPLY: 1980-2000

		YEAR 1980	1985	1990	1995	2000
Installed Capacity (GW)		81.6	96.7	103.3	114.2	137.0
Peak Load (GW)		61.5	73.9	84.7	96.0	114.5
Planned Reserve (GW)		9.7	11.6	13.2	14.8	17.7
Surplus (GW)		10.4	11.2	5.4	3.4	4.8
Primary Energy	Hydro	59	58	56	55	54
Source[2] %	Coal	18	19	21	22	23
	Oil	10	9	8	7	7
	Gas	6	4	4	4	3
	Nuclear	7	10	11	12	13

Source: NEB Internal Estimates
(1) Includes gas turbine, internal combustion capacity, and other peaking plants, as well as base load capacity.
(2) Other primary energy sources are estimated to produce less than 1% to electricity supply.

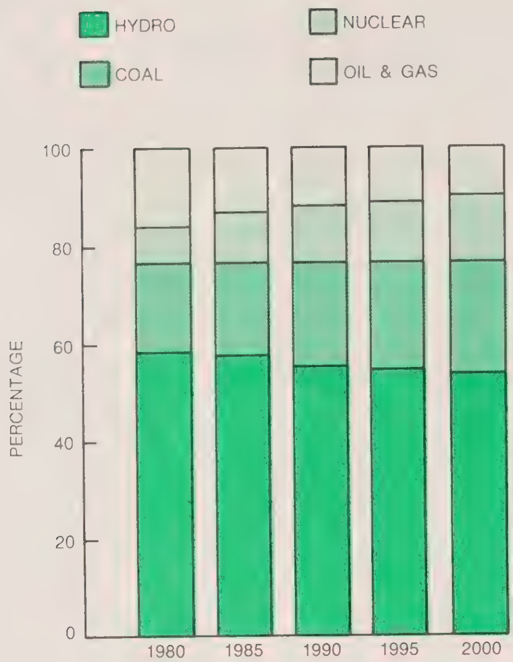

Figure 13-2 Electricity - Installed Capacity by Fuel Type

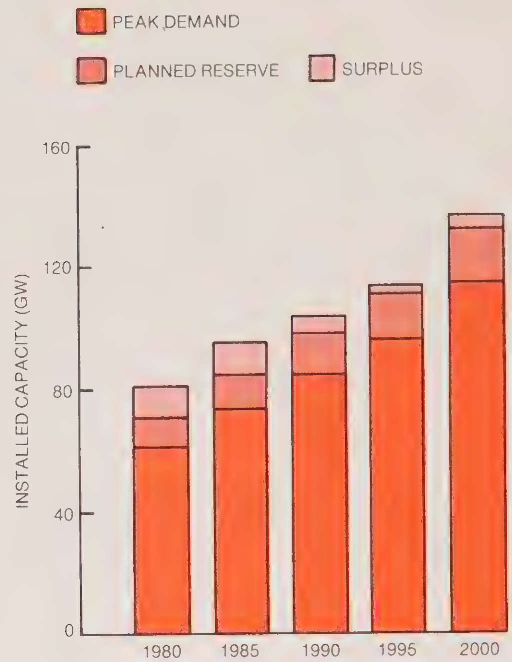

Figure 13-4 Electricity - Capacity Reserve Margin Above Peak Demand

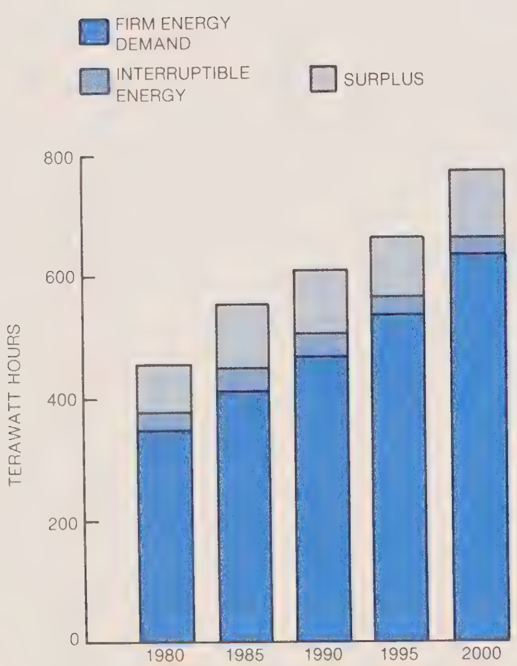

Figure 13-3 Electricity - Energy Margin Above Firm Demand

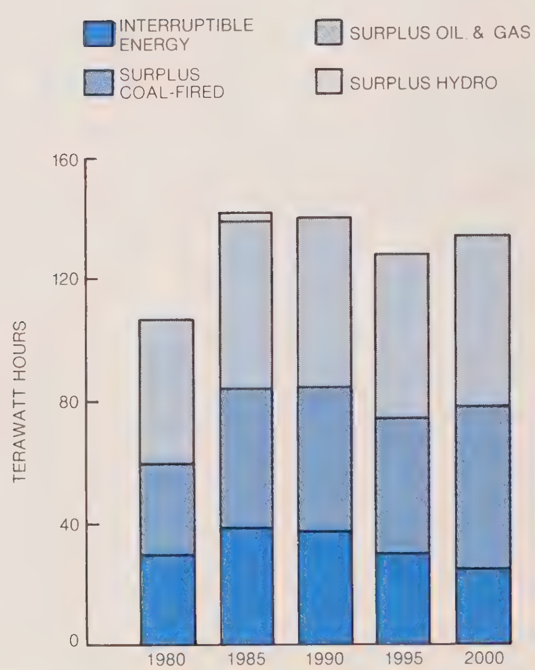

Figure 13-5 Electricity - Energy Margin by Fuel Type

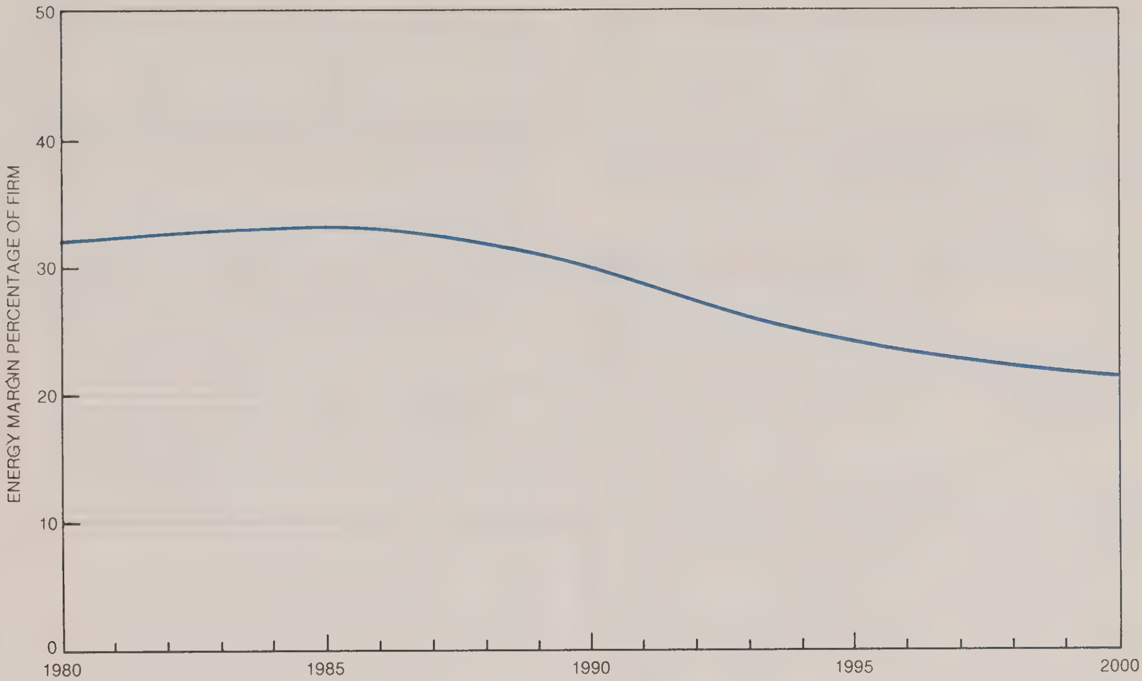

Figure 13-6 Electricity-
Percentage Energy Margin

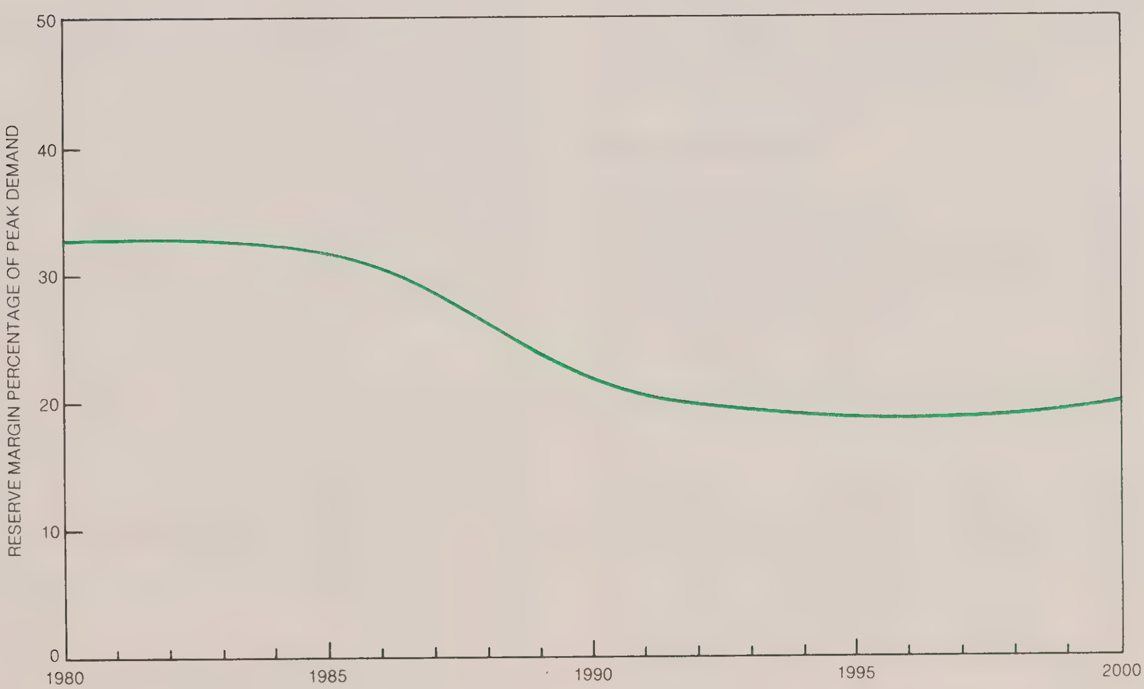

Figure 13-7 Electricity -
Percentage Capacity Reserve Margin

13.3 Hydroelectricity

Views of Submittors

The Province of Newfoundland and Labrador, Manitoba and British Columbia have affirmed predominantly hydroelectric-based supply forecasts. Québec's policy for electric energy is hydro-based.

Newfoundland's submission placed emphasis on development of the Lower Churchill River sites at Gull Island (1 700 megawatts) and Muskrat Falls (600 megawatts) in its supply planning, with additional resources of 4 500 megawatts in northern Labrador and in the St. Lawrence watershed. Also under study is the recall of Churchill Falls energy, now sold under long-term contract to Hydro-Québec.

Newfoundland would use most of this Labrador energy on the Island. Nfld Light, the major distributing utility, stated that it was relying on Labrador energy to meet forecast demand. Transmission of Labrador power to the Island would add nearly four cents per kilowatt hour to the price of energy. Hydro sources are sufficient to meet electricity demand until 2000.

Newfoundland expressed a willingness to sell surplus Labrador energy to outside customers, including United States utilities, at competitive rates. This latter course would require a transmission outlet through Québec, an issue still unsolved. Newfoundland proposed that transmission of power across Québec should be dealt with by the NEB.

Manitoba foresaw the development of 6 000 megawatts of additional capacity on the Churchill, Nelson and Burntwood Rivers. Manitoba considered that surplus energy would be available for sale in neighbouring provinces or in the United States. A study to determine the feasibility of transmitting hydro energy to Saskatchewan and Alberta via a western grid is under way. Hydro sources are sufficient to meet electricity demand to 2000.

British Columbia's supply strategy is based on continued development of hydro potential which, with some coal-fired generation, would be adequate to 2000. It stated that its present program will meet demand to 1988, and presented a list of options without a definitive generation expansion program. The province noted that, of 157 600 megawatts considered economically developable, possibly 87 650 megawatts could not be considered practical for environmental reasons.

Québec's views as contained in the White Paper on Energy were heavily weighted towards continued hydro development. Capacity in 1990 was estimated to reach 41 900 megawatts, mostly remote from the load centres which are in the Montreal to Québec City area. Québec also addressed the potential for development, with Newfoundland and Labrador, of the St. Lawrence North Shore rivers. Québec continues to look upon export to Ontario, New Brunswick and to the United States as markets for its surplus energy. Its hydro resources could provide for electricity demand to 2000.

Although Saskatchewan's system is now predominantly (62 percent) thermal, plans were included to increase hydro generation to 37 percent of its electricity supply by 2000.

New Brunswick is investigating both small and large sites, including a redevelopment of the Grand Falls plant on the Saint John River.

Ontario's uncommitted program includes a further 600 megawatts of hydro, subject to engineering, environmental and economic review.

A number of submittors — British Columbia, NBEPC, Nfld. Light discussed the potential for development of small sites. Nova Scotia, in a joint program with the federal government, is testing a new design of turbine generator in a small (20 megawatts) tidal installation at Annapolis Royal.

Other Information

Although Alberta did not make a submission to the Inquiry, the Electric Utility Planning Council has provided the Board with a copy of its submission to the AERCB, with a number of alternative generation plans, among which hydro sites were considered to be developable in the 1990s (Dunvegan — 1 000 megawatts, Slave River — 1 670 megawatts).

Views of the Board

In all provinces except Prince Edward Island an unquantified amount of untapped hydro is in micro or low head sites which have not been economic to develop. The rate at which the energy will be harnessed is seen as a function of the economics of individual sites. Higher development costs are expected as less desirable sites are developed; Muskrat Falls in Labrador is estimated to cost $2,600 (1980 dollars) per kilowatt, and transmission to the island will add perhaps four cents per kilowatt hour. Newfoundland expressed its preference for hydro rather than nuclear generation. The long life of hydro installations, the low operating costs and continuing inflationary effects are seen as offsetting high first cost. This "inflation proofing" aspect of hydro seems to make it generally desirable. Transmission from remote sites will not be an obstacle and technology is generally adequate for construction of the physical plant.

The Board expects the share of electricity generated at hydro sites in Canada will decline from 68 percent in 1980 to about 56 percent in 2000.

13.4 Primary Fossil Fuel Supplies

13.4.1 *Coal*

Views of the Submittors

The Coal Association of Canada foresaw no major breakthrough for the industry in supplying coal for thermal generating stations. Ontario Hydro stated that costs of western Canadian coal were higher than those of American coal, because of transportation differentials.

Conversion of existing oil-fired plants to coal-firing is being studied by NBEPC (approximately I 000 megawatts) and by Nova Scotia (560 megawatts). Newfoundland stated that conversion of its 450 megawatt Holyrood station could not be decided until the question of Labrador hydro was resolved.

Nova Scotia has opted for a coal-based generation program, heavily dependent on parallel investment by DEVCO, and others, for supplying its needs. DEVCO argued that it would be able to meet future demand for thermal coal. New coal-fired equipment is already committed, to be followed by conversion of Point Tupper and Tuft's Cove oil-fired generation to coal by 1987.

NBEPC estimated that domestic coal production could support a further 200 megawatts of plant. Conversion of the Coleson Cove plant would create a demand which could be satisfied only by imported coal. The Commission is also investigating peat deposits in northern New Brunswick.

Ontario Hydro is reviewing the potential for developing another coal-fired plant in Northern Ontario to use the Onakawana lignite deposit. It has determined that there would be a market for surpluses from its existing coal-fired generation, as economy energy, in the neighbouring United States utilities which have oil-fired plants.

SPC estimated that 62 percent of its electric energy in the year 2000 would be generated using lignite fuel, although it had not committed itself to a generation plan for the full period.

British Columbia, although continuing a basic hydro strategy, has under study a 2 000 megawatt coal-fired plant based on the Hat Creek coal deposits, and a 600 megawatt plant in the East Kootenay to burn waste from a metallurgical coal mining operation. These projects were not included in a committed generation plan.

The burning of coal raises a number of environmental considerations including acid rain. NBEPC raised this question both in respect of burning high sulphur New Brunswick coal, and in complying with provincial regulations in respect of burning coal at Dalhousie. It was also stated to be a consideration if Coleson Cove units are converted.

Nova Scotia discussed environmental problems but did not consider them to be serious while burning Cape Breton coal. Ontario Hydro raised the possibility that environmental regulations might force increased consumption of low sulphur western Canadian coal. SPC did not rate acid rain as a serious constraint, because its coal had low sulphur content.

Views of the Board

Canadian coal, along with uranium and hydro, is an indigenous resource available for electricity generation. Its use in Nova Scotia and Saskatchewan is assured. In Alberta, coal will provide 90 percent of the electric energy by 2005. Québec and Manitoba, however, see little place for coal.

The Board speculates that future generation in Prince Edward Island could be coal-fired, but this was not confirmed.

While it appears that Canadian coal will be used in other provinces to some extent, the high cost of transportation is seen as a constraint in competition with other fuels. Environmental pollution is a further constraint, both because of the technical problems it raises, and because of the cost of removing pollutants from flue gases.

Most of the coal required by Ontario Hydro will continue to be imported from the United States and, if conversion plans go ahead, United States coal may play a part in New Brunswick and Newfoundland.

In sum, the Board expects that in the period 1980-2000, coal's share of the generation of electricity will increase to nearly one quarter of Canada's demand for electricity.

13.4.2 *Oil and Natural Gas*

Oil

The off-oil strategy set out by the NEP, and the high cost of oil are expected to limit the use of oil for generation of electricity. Chapter 13.4.1 comments on the conversion of oil-fired plants to coal.

Views of Submittors

The conversion of 1 600 megawatts of oil-fired capacity in service in New Brunswick and Nova Scotia is under study. New Brunswick's Coleson Cove plant was designed to burn heavy oil or crude, with 400 megawatt of the 1 000 megawatt capacity being committed under a unit participation agreement to New England utilities. This contract, which terminates in 1986, has now been reduced to 133 megawatts but New Brunswick expected to continue to burn a varying amount of oil in this and other plants.

Nova Scotia, too, stated that there will be a continuing requirement for some heavy oil, possibly increasing above present levels in the near term. Ontario Hydro planned to mothball two units at Lennox, at least for the short term. Newfoundland stated that it cannot change the operating mode at Holyrood until the future of Labrador hydro is decided.

Views of the Board

The Board noted the concern of all utilities having oil-fired capacity with the increasing prices of oil, and the intention expressed to limit consumption to the extent possible. No new construction of oil-fired capacity is scheduled. The role of established plants, if not converted to coal-firing, is projected to be as reserve or for use at peak times. There is no reason to expect any substantial export potential, since the cost of exported energy is based on uncompensated fuel.

In the Atlantic Provinces, which have been most dependent on imported oil for electricity generation, it is expected that consumption will fall from approximately 2.8 million cubic metres in 1980, to less than 1 million in 1986 (after Nova Scotia's coal conversions) and substantially lower still if a decision is reached to convert New Brunswick's Coleson Cove plant to coal.

Prince Edward Island's policy, with nearly all oil-fired generation, is not known. Its primary source of energy is, however, the NBEPC system through an underwater cable. The Board expects that Prince Edward Island will purchase most of its electricity from NBEPC supplemented by its own oil-fired generation.

The Board also notes that other fuels are being substituted for oil in co-generation plants, where electricity is produced as well as process steam.

In sum, the Board expects heavy fuel oil will be used to generate less than one percent of electric energy by the year 2000, mostly for peaking or emergency use. A limited (perhaps 0.3 percent) consumption in diesel plants in remote locations is expected to continue.

Natural Gas

The National Energy Policy discourages natural gas fueling of thermal generating stations. The 1980 installed gas-fired capacity totalled 4 479 megawatts.

Views of the Submittors

With regard to the proposed construction of a gas pipeline from Québec City to Halifax, NBEPC stated that there was a temporary role for gas at the Coleson Cove station. The Government of Nova Scotia indicated that natural gas would be an addition to the range of energy sources available to the region, but its policy would not be to use gas for electricity generation. Natural gas generation was not included in either province's generation expansion plans. Testimony by H. Zinder & Associates respecting gas demand in the two provinces showed a thermal generation market, based on data received from the provincial utilities.

Saskatchewan testified that the use of gas for thermal generation in the province would be negligible in 2000, although it had not completely discounted this alternative. British Columbia stated that the Burrard Inlet plant (900 megawatts) would be used in low water years to supplement hydro resources, but saw no expansion of capacity. Ontario's forecast planned less than 0.5 percent of its electricity from gas.

Views of the Board

There is some uncertainty surrounding short-term use of gas in New Brunswick and Nova Scotia. However, the Board notes that utilities are not planning to develop any new base load gas-fired capacity in the future, and that existing plants will be used for peaking or emergency operations; the Board expects, therefore, that the use of gas for electricity generation will decline to less than two percent of the national electricity demand, including any new gas turbine installations for peaking purposes.

13.5 Nuclear Fuels

Views of the Submittors

The Province of Ontario and Ontario Hydro concluded that Ontario's electric energy would be supplied increasingly from nuclear sources, increasing from 30 percent in 1979 to 56 percent in 2000. Ontario Hydro's economic analysis confirmed that postponement of construction of nuclear reactors by utilization of coal- and oil-fired generation already available would result in higher electricity costs to its customers.

New Brunswick's single 630 megawatt nuclear reactor at Point Lepreau is expected to begin commercial operation in 1982. The site was projected to accommodate a maximum of four reactors. Consideration (with no firm plans) was being given to operation of a second reactor in the early 1990s, contingent upon finding markets for its output. New Brunswick planned to export a significant proportion of its nuclear generation.

Québec's Gentilly II reactor is expected to come into service in 1983, but there are no firm plans for additional nuclear plant construction.

Views of the Board

In spite of the reaffirmation in the NEP of the federal subsidy of part of the cost of construction of the first reactor in any province, no province other than Ontario and New Brunswick indicated that nuclear generation would enter into generation expansion plans. Nonetheless, the share of nuclear generation of electricity is expected to increase from 10 percent to about 17 percent.

There are continuing concerns as to the environmental effects of the operation of nuclear reactors, the potential for nuclear catastrophe, the disposal of spent fuel, and the decommissioning of nuclear sites. The lead time to commercial operation, now estimated at 10 to 14 years in Canada, is in part a result of the necessity to satisfy regulatory, environmental and safety requirements, and to ensure the involvement of the public in the projects. This does not, however, preclude an increasing contribution to Canadian energy requirements before 2000, if utilities should choose this energy source, or even the export of energy generated by CANDU reactors located in Canada.

The Board notes that no submissions were received from the mining industry, from the fuel processors, from the design consultants or from the construction industry.

13.6 Hog Fuels, etc.

Views of the Submittors

British Columbia is studying a proposal to construct a 60 megawatt plant at Quesnel, B.C., to burn wood waste generated in local forest industries.

Ontario has studied hog fuel as a potential generating source, but has concluded that its use is uneconomic at this time.

New Brunswick, Nova Scotia, British Columbia and Ontario recognized the potential in the forest industry to use hog fuel in co-generation projects, where generation of electricity is coordinated with the production of process steam.

Views of the Board

It is the view of the Board that the contribution of hog fuel as an energy source will be significant mainly in co-generation projects, reducing the electricity demand of large industrial plants, rather than through a major input to the utility supply system. Its total electricity generation is not expected to exceed 0.5 percent of electricity demand.

The Board notes also that there have been proposals to combine the generation of electricity and the provision of process

steam for large industrial parks or for residential heating in large towns. However, the difficulty of matching the 10 to 12 year utility planning period with the much shorter planning periods for industrial plants or for residential construction makes the widespread application of this concept difficult.

13.7 Other Supplies

13.7.1 *Wind Energy*

Views of Submittors

Several provinces stated that experimental projects were under way, usually in collaboration with the National Research Council (NRC), in the design, construction and operation of modern wind-driven generators. Submittors generally agreed that this type of equipment might supplement other forms of generation, particularly in remote areas in which diesel generating units are usually installed.

Views of the Board

The Board agrees that wind-power may be valuable in some locations, but total energy generated will not be of a significant level in the national supply picture over the forecast period. None has been included in the Board's estimates.

13.7.2 *Tidal Energy*

Views of Submittors

The submission of the Government of Nova Scotia expressed the view that tidal power in the long run would provide useful energy for the province and for export. Evidence revealed uncertainty both as to cost and to markets, and the project was not included in the province's generation expansion plan. Tidal power was also mentioned in the submissions of New Brunswick and British Columbia but was not scheduled in either province's program. Nova Scotia reported that a 20 megawatt tidal installation is being built near Annapolis Royal to test the operation of a new type of low-head turbine.

Views of the Board

The Board is aware of the long history of studies of tidal power in the Bay of Fundy. Its development is contingent upon resolution of technical problems and the economics of development and utilization of this cyclical energy source. Testimony in the hearing did not establish a case for the early development of this resource, and none has been included in the Board's estimates.

13.7.3 *Solar Energy*

Views of Submittors

CSIA mentioned electric energy generation through photovoltaic, photochemical, solar thermal electric and solar satellite power systems, affirming at the same time the Association's view that the significant contribution would be made in low temperature active solar (residential) heating.

The largest installation (2.4 kilowatts) of photovoltaic cells in Canada is now being made by Ontario Hydro in collaboration with the NRC.

Views of the Board

The size and cost of existing and planned installations suggest that the contribution of direct solar generation of electric energy will not be significant in the electric supply industry prior to the year 2000, and no provision has been made in the Board's estimates. (The solar energy use for heating purposes is included in Chapter 14).

13.7.4 *Other Sources of Energy*

Views of Submittors

Among the forms of energy mentioned but not in present use were geothermal, biomass, wave action and municipal garbage. No Submittor included generation from these sources in its supply program. Ontario Hydro referred to "load management" as a resource, with a potential for peak load reduction of 2 000 megawatts by 2000. Its forecasts, however, did not take this potential reduction into account.

Views of the Board

These other sources are unlikely to provide a significant amount of energy to Canadian supply systems by 2000, and no provision has been made in the Board's estimates.

13.8 Summary of Supply of Electrical Energy

Views of the Board

Figures 13-1, 13-2 and Tables 13-3, 13-4 provide the Board's forecast of generation of electricity over the period from 1980 to 2000, of installed capacity, and of the primary energy sources. It is expected that energy demand will increase by 81 percent and peak demand by 87 percent. An increasing emphasis on coal, hydro and uranium in plans for future generation is evident. Given the relative abundance of these resources in Canada, there is no apparent constraint to meeting future demand.

The industry presently has excess generating capacity. Therefore increased demand, whether from a higher load growth rate, or from an increase in off-peak consumption resulting from changes in social patterns, rate structures or load management initiatives by electric utilities, could be satisfied. A peak, possibly 15 percent higher, and energy demand of 30 percent above present levels, could be met in the near term, without capital investment and while still providing the generally accepted margins of system reserve. Figures 13-3 to 13-7 show the surplus graphically, from data derived from the Board's generation expansion model (see Tables 13-3 and 13-4).

Since this is a national aggregation, the position in each province may differ substantially from the national picture. Surplus has risen because construction programs were based on forecasts of higher rates of growth than have actually occurred. The cost of incremental energy would be somewhat higher than

present average levels because most of it would be thermally generated from coal-, oil- and gas-fired plants.

Increased demand in the future could equally be satisfied within construction constraints of 6-9 years for thermal or hydro capacity and 12-14 years for nuclear reactors, part of this period being due to regulatory procedures. No technological, financial, or energy source constraints are seen as preventing the supply of any reasonable level of energy or peak demand to 2000.

Export, whether interprovincially or internationally, is looked upon as a safeguard against the financial penalties of falling demand growth rates, and perhaps to assist in advancing construction, or building larger projects than would otherwise be possible. Provincial government policies generally support exports when advantageous to provincial customers. The Board will continue to review applications for export in accordance with its mandate under the National Energy Board Act. The Board noted, however, that strong interconnections, both north-south and east-west, afford protection against the costs of over- and under-building of generating capacity.

Existing technologies in both electricity generation and transmission are adequate to meet supply requirements over the period under study. The alternate energy forms – solar, wind, biomass, geothermal, tidal – are not likely to make a major contribution to electricity supply. The more technologically advanced developments – breeder reactors, magnetohydrodynamics, fusion – did not enter into the Submittors' testimony, and it is concluded that more research and development is necessary before these become commercially feasible. There appears, however, to be a significant potential for small hydro plants, a resource which has been neglected in the recent past.

CHAPTER 14
SUPPLY OF ENERGY FROM COAL

14.1 Introduction

Coal dominated Canada's energy supply for more than half a century until it was displaced by oil and gas in the 1950s and 1960s. Despite its diminishing importance in the preceding decades, coal represents a significant energy form in the Canadian energy balance. The role of coal in Canada is a complex one due to its distribution in relation to the established coal markets and due to the availability of other energy resources with which coal must compete in Western Canada.

Few Submittors addressed the subject of coal supply. Those who did generally confirmed that Canada's coal resources are very large and were expected to provide the future expansion of coal production which is currently demand-constrained.

14.2 Coal Resources and Reserves

Views of Submittors

The Coal Association of Canada submitted an estimate of Canadian coal resources based on a Department of Energy, Mines and Resources study. This estimate is summarized in Table 14-1.

Shell stated that one of its subsidiaries was a member of Coal Assn. and supported its submission to this inquiry. Shell also stated that EMR's 1979 coal resource estimate of some 474 gigatonnes was reasonable. Shell forecast that Canadian coal resources would meet domestic demand for indigenous coal and leave a sizeable surplus for exports.

Nova Scotia submitted that the province has more than 3.1 gigatonnes of coal present in the various coal basins of the province with the bulk of this resource located in the Sydney coalfield. Of this, Nova Scotia felt that no more than one-third would eventually be extracted.

British Columbia estimates its reserves of thermal and metallurgical coal to be 1 285 megatonnes and 1 520 megatonnes respectively, while resources were estimated to be 38.2 gigatonnes.

Views of the Board

The Board has considered the evidence presented on coal resources and reserves and has evaluated the relevant public documents. The Board adopts for the purpose of this report the coal resources estimates of EMR as published in Coal Resources and Reserves of Canada — Report ER 79-9. These estimates are summarized in Table 14-1. EMR believes these estimates to be conservative as they are based on limited data, and do not include any estimates for Newfoundland, Manitoba and all of Canada north of 60 degrees North latitude. Indications are that the resources of Northern Canada will be shown to be very large when reliable information becomes available.

The Board believes that current reserves plus potential reserves additions from the resource base will be sufficient to meet Canadian requirements for indigenous coal plus provide coal to the export market during the forecast period.

Table 14-1

ESTIMATE OF COAL RESOURCES AND RESERVES OF CANADA(1)
(Megatonnes)

		Resources of Immediate Interest			Resources of Future Interest			Reserves	
Provinces	Rank	Measured(2)	Indicated(2)	Inferred(2)	Measured	Indicated	Inferred	Mineable(3)	Recoverable(4)
Nova Scotia	Bituminous	223	543	757	3	50	128	370	89
New Brunswick	Bituminous	32	16	1	—	—	—	46	33
Ontario	Lignitic	218	—	—	—	—	—	218	
Saskatchewan	Lignitic	1 499	2 681	3 436	161	3 913	2 3512	2 150	1 720
Alberta	Bituminous	9 300	—	26 700	—	—	—	2 457	530
	Sub-bituminous	30 000	—	102 000	—	–198 000	7 328	2 182	
British Columbia	Bituminous	7 282	9 898	44 036	—	—	—	2 683	955
	Lignitic	1 845	91	7 439	—	—	—	839	397
Total Canada	Lignitic	3 562	2 772	10 875	161	3 913	23 512	3 207	2 117
	Sub-bituminous	30 000	—	102 000	—	—	198 000	7 328	2 182
	Bituminous	16 837	10 457	71 493	3	50	128	5 556	1 607

(1) Data in this table is adapted from Energy Mines and Resources Canada Publication *Coal Resources and Reserves of Canada - Report ER 79-9*
(2) The terms measured, indicated and inferred denote the precision with which given quantities of resources have been determined or estimated.
(3) Mineable reserves include that portion of measured and indicated resources of immediate interest that can be considered for mining using current technology, and applying broad economic judgment as to the mining method.
(4) Recoverable reserves is that portion of mineable reserves that could be recovered as run-of-mine coal with current technology and prices. The coal deposit must be legally open to mining, and the necessary infrastructure must be in place or could be amortized through coal sales.

14.3 Production

Views of Submittors

Coal Assn. submitted information on the production of coal in the various regions of Canada.

It stated that, in the Cordilleran region, mining operations varied according to the local geological conditions and several pits might be in operation on any one property at a given time. Coal Assn. submitted that the expansion of current mining operations and development of new mines was currently limited by demand. It stated that any continuing expansion of supply from this region would require a steady improvement in mining technology to permit the economic recovery of the larger part of the resource that must be mined underground.

In the Foothills region of Alberta, mining conditions were stated to be generally less severe than in the Cordilleran region. Coal Assn. submitted that eventually most of the resources in the Foothills region would have to be extracted by underground mining methods.

Coal Assn. referred to the fact that in the Plains region of Alberta and Saskatchewan the problems encountered were essentially those of planning and operating large scale enterprises and addressing environmental impact problems of air and water quality and land reclamation. Draglines were a key piece of equipment in this region and their delivery time would affect the rate at which new projects could be brought into production.

Coal Assn. stated that in the Atlantic region higher production rates have been achieved recently and plans for modernization of mining methods might result in further production increases.

Gulf submitted that the supply of coal would be dependent on development of coal reserves induced and/or constrained by domestic and export demand, by price of coal and competitive fuels, by cost of production, by the infrastructure and perhaps by the labour force availability.

Nova Scotia stated that current producing capacity was approximately 2.8 million tonnes annually. Projected coal mining capacity in the year 1991 would be 7.7 million tonnes per year.

British Columbia forecast a substantial increase in metallurgical coal production, with production levels reaching 18.5 to 21.9 million tonnes by 1996. Thermal coal production in 1996 was forecast to be 7.9 million tonnes. Even at these suggested production levels, British Columbia expected only a small fraction of the reserves would be used and therefore availability would not be a problem.

Views of the Board

It is the Board's view that production of coal is now principally constrained by available markets for coal. Other factors including technology, equipment and labour availability, environmental constraints, government regulations and fiscal policies, and transportation system availability could set a limit to the rate of development of coal production. However, the Board foresees no problems in meeting Canadian requirements for Canadian coal which are given in Table 14-2.

Table 14-2

CANADIAN DEMAND FOR THERMAL COAL

Year	Total[1] Demand (PJ)	Imports[2] (PJ)	Domestic Demand (PJ)	Volume[3] (Megatonnes)
1981	823	396	427	19.4
1982	878	419	459	20.9
1983	852	402	450	20.5
1984	820	300	520	23.6
1985	888	319	569	25.9
1990	1 069	357	712	32.4
1995	1 447	459	988	44.9
2000	1 773	493	1 280	58.2

(1) Coal used in electric power generation was assumed to represent approximately 94 percent of total demand for thermal coal.
(2) Nearly all the demand for thermal coal in Ontario is assumed to be supplied by the United States.
(3) Demand for coal was converted from heat units to volume using an average conversion factor of 22 GJ/tonne.

PART IV

BALANCING SUPPLY / DEMAND

CHAPTER 15
LONG TERM EXPORT AUTHORIZATIONS

15.1 Natural Gas Exports

Currently Authorized Exports

To determine the surplus of natural gas, the Board had to establish the annual quantities which might be exported under long-term existing licences which go up to 1995. Remaining quantities of natural gas under each licence for export as of 31 December, 1980 are given in Table 15-1.

TABLE 15-1

REMAINING QUANTITIES IN EXISTING NATURAL GAS LICENCES
As of December 31, 1980

		$(10^{6}m^{3})$	(PJ)
A&S	GL-3	27 011.2	1 036.7
	GL-16	17 844.7	684.9
	GL-24	27 581.4	1 058.6
	GL-35	11 222.1	430.7
CMPL	GL-5	1 909.3	73.3
	GL-17	1 822.2	70.0
	GL-25	1 382.4	53.1
	GL-36	698.6	26.8
	GL-52	1 652.1	60.7
	GL-53	86.2	3.3
	GO-3	105.0	3.9
WTCL	GL-4	10 837.1	415.9
PAG	GL-58	37 324.8	1 450.8
	GL-59	13 685.7	532.0
	GL-62	7 914.8	307.6
	GL-63(1)	4 632.8	180.1
	GL-63(2)	1 588.0	61.7
WTCL	GL-41	84 186.7	3 354.0
CGDC	GL-54	2 394.0	95.4
ICG	GL-28	147.7	5.5
	GL-29	3 490.1	130.9
NGL	GL-6	928.6	34.8
	GL-55	717.5	26.9
TCPL	GL-1	148.6	5.6
	GL-18	16 118.9	604.8
	GL-19	1 706.1	64.0
	GL-20	10 944.2	410.6
	GL-37	20 253.4	759.9
	GL-38	5 263.2	197.5
	GL-39	751.0	28.2
	GL-43	8 295.7	311.3
	GL-56	17 050.0	639.7
	GL-57	1 600.3	60.0
	GL-60	10 096.4	378.8
	GL-61	11 269.8	422.8
Total Canada		362 660.6	13 980.8

(1) Firm
(2) Conditional

The Board made the following fundamental assumptions in regard to allowances for the amounts and the duration of possible annual exports of gas under existing licences:

(1) For licences containing provisions permitting annual averaging, the Board used the maximum daily licensed quantity (adjusted for heat content), times the number of days in the year, to calculate each annual quantity;

(2) For licences not containing provisions for annual averaging, the Board used the maximum annual licensed quantity (adjusted for heat content); and

(3) For the duration of the allowance specified in (l) and (2), the Board used the lesser of the following periods:
   a) until the expiry of the term of the licence; or
   b) until such time when the remaining term volumes would have been exhausted if gas were exported at the level of the annual quantity stated in the licence.

The Board believes that this procedure is a realistic approach to providing a level of exports which should be protected under the Deliverability Tests. The allowance given for natural gas export licences is contained in Appendix T.

In the early years, the allowance made for exports exceeds the level of exports that the Board expects will prevail. The allowances made by the Board do not impinge on the rights of existing licensees to operate within the conditions of their licences. It should be recognized, however, that annual averaging clauses do restrict the amount of gas which can be authorized under the Deliverability Tests.

15.2 Natural Gas Liquids Exports

The approved natural gas liquids export licences as of February, 1981 are given in Appendix U. In addition, the Board authorizes under quarterly and monthly orders, the export of propane and butanes which it deems to be surplus after allowance is made for Canadian requirements and previously licenced exports.

15.3 Electricity Exports

A summary of committed exports of electricity is presented in Table 15-2. The table shows net authorized exports under firm licences. Analysis shows that actual exports under these licences are normally about 75 percent of the authorized quantities.

The table does not show exports of short-term firm power which require Board approval on a contract-by-contract basis, nor does it show diversity exchanges which result in no net export. Licence EL-96 issued to Hydro-Québec authorized exports of up to 3 000 gigawatt hours per year until 1981. Thereafter, net export quantities are to be set by Hydro-Québec and are subject to the Board's approval each year until the licence expires in 1991.

Most electricity exports from Canada are made at the discretion of the exporters, under interruptible licences. Total exports are discussed in Section 16.4, which deals with balance of electricity supply and demand.

TABLE 15-2

COMMITTED EXPORTS OF ELECTRICITY
SUMMARY OF LICENSED FIRM EXPORTS

Exporter	Licence	Authorized Quantity (GW.h) 1980	1985	1990	1995	2000
Maine & New Brunswick Electrical Power Company, Limited	EL-22	250	250	—	—	—
Fraser, Inc.	EL-122	400	400	—	—	—
NBEPC	AO-1-EL-64	3 504	3 504	—	—	—
Hydro-Québec	EL-96	3 000	—	—	—	—
	EL-106	17	—	—	—	—
	EL-132	—	189	—	—	—
Ontario Hydro	EL-32	15	15	4	—	—
Canadian Niagara Power Company Limited	EL-124	130	—	—	—	—
Boise Cascade Canada, Ltd.	EL-62	307	—	—	—	—
Manitoba Hydro	EL-98	876	876	876	—	—
SPC	EL-117	—	438	—	—	—
British Columbia Hydro and Power Authority	EL-126	32	—	—	—	—
Miscellaneous Orders		12	—			
TOTALS (GW.h)		8 543	5 672	880	—	—
TOTALS (PJ)		31	20	3	—	—

CHAPTER 16
ENERGY BALANCES

16.1 Petroleum Balances

Introduction

Although Canada is now a net exporter of energy, it is not self-sufficient in oil. Canada has an inadequate supply of light crude oil and a surplus of heavy crude oil. This surplus is currently being exported. Long lead times are necessary to develop facilities to utilize this heavy crude oil in Canada and to develop new crude oil sources particularly in the frontier areas and from the large deposits of oil sands.

The pattern of oil flow in Canada is complicated not only by the different grades and sources of crude oil but also by exchanges between Canada and the United States and by the allocation of domestic light crude oil among Ontario and Québec refiners.

The demand for crude oil has now stabilized and declines are expected to continue during the 1980s as conservation and the effects of the government off-oil policy continue. During the 1990s oil demand is expected to grow again because foreseen technology in the transportation sector is expected to limit the substitution of other energy forms for oil and because by 1990 conversions from heating fuel oil products to other energy sources is expected to be essentially complete.

Views of Submittors

All Submittors who provided a supply/demand balance for oil, forecast a shortfall during the mid 1980s. With an aggressive exploration and development program, most agreed that Canada could be self-sufficient in oil in the 1990s. However, with the introduction of the NEP, most Submittors forecast that imports would continue to rise over the forecast period to levels between 100 and 150 thousand cubic metres per day by 2000. A few Submittors pointed out that there would be imbalances between supply and demand for heavy crude oil as well as for heavy fuel oil. The role of the Sarnia-Montreal pipeline was highlighted by a few Submittors, showing it lacks capacity to supply Montreal, or suggesting it be reversed in order to supply Sarnia with imported oil, depending on the economic scenario used.

Texaco stated that Canada's oil supply would be insufficient to meet demand during the next two decades. Net imports of between 25 and 70 thousand cubic metres per day would be required throughout this period. Texaco also assumed that if domestic crude oil prices were equated to Chicago prices by 1985, net imports could be reduced to about 15 thousand cubic metres per day for the remainder of the forecast period.

Petro-Canada forecast that Canada would have severe oil shortage problems over the next five years. After 1986, Petro-Canada stated that the domestic supply picture should improve and Canada was expected to move to self-sufficiency over the decade of the 1990s.

Starting in the late 1980s, Gulf, using a high case example, identified the Sarnia-Montreal pipeline as a constraint on potential displacement of imported oil by Western Canadian production and frontier supplies since it would not have sufficient capacity. However, Gulf stated that the Sarnia-Montreal pipeline would operate below its capacity by about four thousand cubic metres per day in the period 1984-86 but this period could be extended if oil sands development were delayed. Gulf forecast that heavy crude oil could remain in surplus quantities, even with some upgrading facilities. Imports of crude oil would continue over the forecast period to be in the 30 to 85 thousand cubic metres per day range. The maximum level of imports would occur in 1985. Even with an optimistic increase in oil sands, heavy crude oil and frontier development, Gulf stated that Canada would be unlikely to become self-reliant during the next 20 years.

Shell forecast imports of oil to increase from their present level of 52 thousand cubic metres per day to 120 thousand cubic metres per day by 1985 and 135 thousand cubic metres per day by 2000 if there were no new production from oil sands and the NEP stayed in place.

Imperial expected that total Canadian imports would exceed 100 thousand cubic metres per day in 1985. If the Cold Lake and Alsands projects were completed in the 1986-89 period, as well as additional oil sands projects and frontier prospects, Imperial stated that Canada could reach self-sufficiency by the mid 1990s. If these projects were not completed, Imperial forecast that after 1985 oil imports would remain slightly higher than 100 thousand cubic metres per day over the forecast period.

Imports in 1985 could be as high as 120 thousand cubic metres per day if oil sands production were replaced by medium gravity imports and a heavy fuel oil upgrader were not available.

With an aggressive development of oil sands and frontier oil, CPA stated that Canada could approach self-sufficiency during the early 1990s. CPA expected that with continuation of oil sands development, plus tertiary recovery projects, oil imports could be eliminated by the early 1990s.

However, CPA expected the NEP to reduce oil production from established reserves, slow down new discoveries and tertiary development as well as oil sands and frontier development, so that by 1990 imports would grow to approximately 150 thousand cubic metres per day.

Norcen forecast imports to rise from present levels to a maximum of about 90 thousand cubic metres per day in 1985 and then to decline to about 25 thousand cubic metres per day by the end of the forecast period. Norcen forecast that Canada could be self-sufficient in oil by 2000 with additional production from the frontier areas or with an accelerated effort in the oil sands and heavy oil.

Although Dome believed it was premature to forecast which supply areas would be developed first, using a base case scenario, imports were eliminated by 1988 and a surplus of some 200 thousand cubic metres per day was developed by 2000. Under a low case scenario, Dome forecast that imports would remain around 100 thousand cubic metres per day over the forecast period with maximum imports occurring around 1985.

NOVA forecast oil imports to reach 100 thousand cubic metres per day by 1986 in its base case. NOVA believed that self-sufficiency in liquid hydrocarbon production could be achieved by the early 1990s provided a pricing system were established to encourage the immediate development of the newer and more unconventional sources of oil.

16.1.1 *Supply Demand Balance Total Crude Oil and Equivalent*

Views of the Board

Base and Modified Base Case Supply and Middle Case Demand

The base and modified base cases for crude oil and equivalent supply are shown in Figure 16-1 along with feedstock requirements generated from the middle case demand for petroleum products. On the basis of these forecasts, Canada would not become self-sufficient in total crude oil supply before the year 2000.

A comparison of the base case supply and the middle case demand shows that Canada's net imports of crude oil will continually increase over the forecast period. Net imports would increase to 95 thousand cubic metres per day by 1985, remain fairly constant through 1990 and then increase steadily to 123 thousand cubic metres per day by 1995 and 183 thousand cubic metres per day by 2000. Figure 16-2 shows the regional impact associated with this supply/demand balance case. The figure indicates that by the year 2000 all of Ontario and even part of the Prairies and British Columbia requirements for oil would have to be met by imports. To accommodate these markets it would appear necessary that the Sarnia-Montreal pipeline would need to be reversed and expanded to allow for large westward movements of crude oil, that new or expanded import facilities would need to be built to provide for placing additional offshore volumes into Montreal and that Ontario refineries would need to be modified to accommodate foreign crudes. Alternatively, large volume imports might be accommodated on the West Coast.

A comparison of the modified base case supply and the middle case demand shows that Canada's net imports of crude oil after increasing to 87 thousand cubic metres per day in 1985 are expected to diminish during the rest of the forecast period to 42 thousand cubic metres per day in 1990, 30 thousand cubic metres per day in 1995 and 24 thousand cubic metres per day in 2000. As illustrated in Figure 16-3, it would be possible that eastward shipment of domestic crude oil in the Sarnia-Montreal

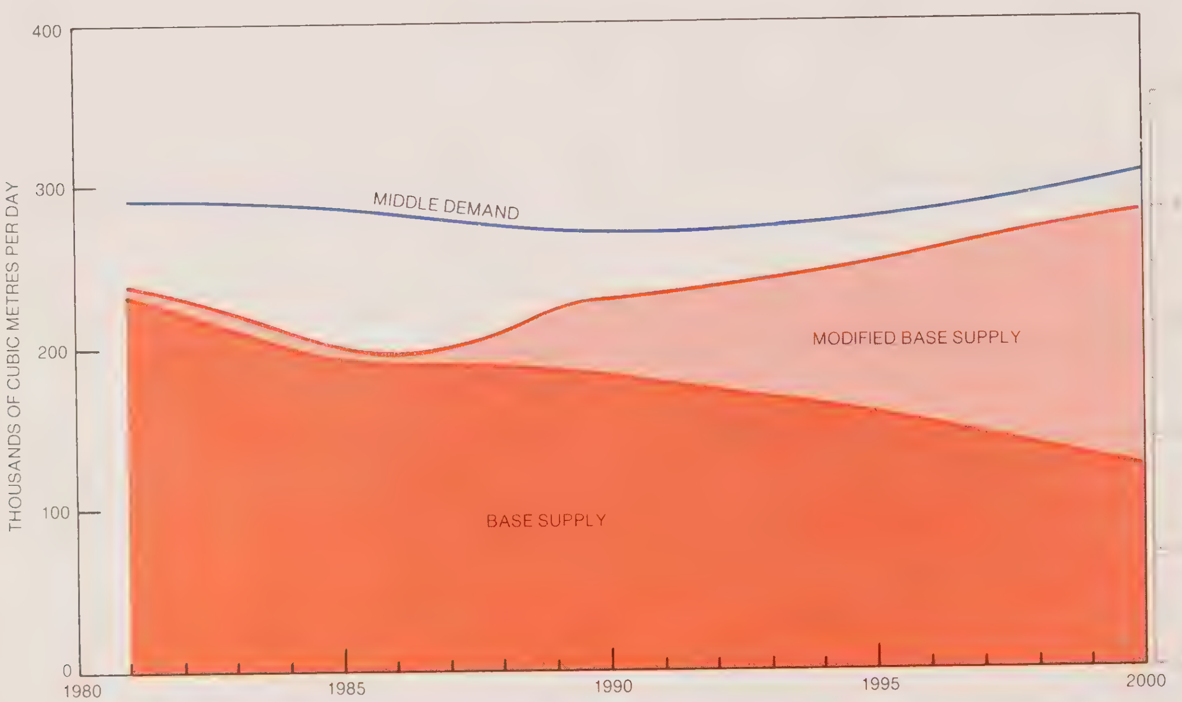

Figure 16-1 Supply & Demand - Crude Oil & Equivalent
Base and Modified Base Supply with Middle Demand

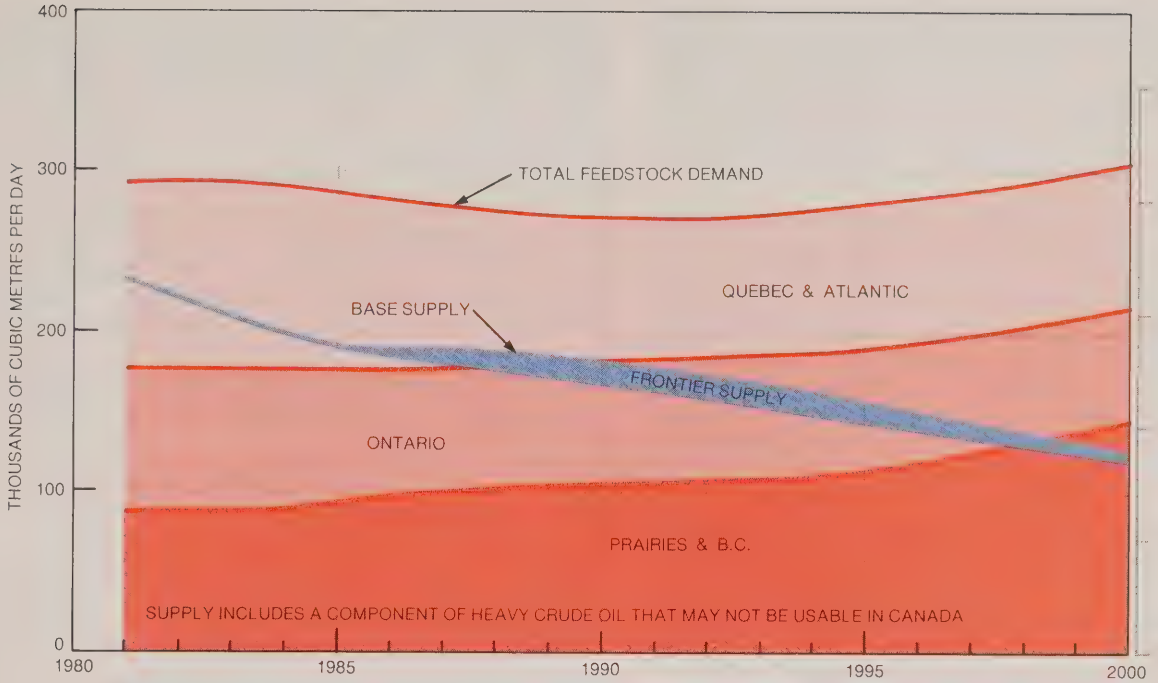

Figure 16-2 Supply & Demand - Crude Oil & Equivalent
Base Supply & Middle Demand
(Regional Components)

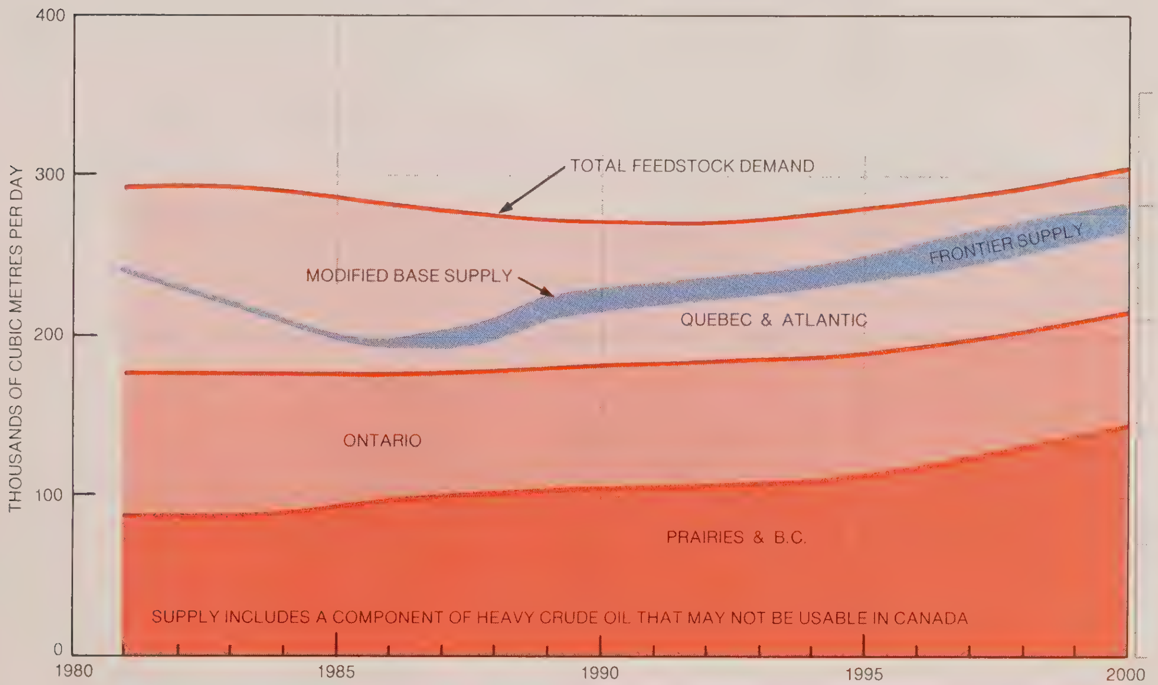

Figure 16-3 Supply & Demand - Crude Oil & Equivalent
Modified Base Supply With Middle Demand
(Regional Components)

pipeline would continue throughout the forecast period; in this case no new import facilities would be required. Refineries in Ontario and West would continue to be supplied from domestic crude oil and imports would occur only in Québec and East.

Supply-Demand Variability

In previous chapters, the Board has developed additional cases in order to indicate the uncertainty of forecasting both supply and demand for crude oil. Figure 16-4 shows the three demand cases as well as the four supply cases for crude oil and equivalent. As can be seen from this graph, the variation in Canada's total demand for crude oil is foreseen to lie between relatively narrow limits over the forecast period. Although there is a slow decline in both the low and middle demand cases in the first decade, requirements are forecast to grow steadily in the second decade to original 1981 levels.

Only in the unlikely case of high supply can Canada become self-sufficient in oil for all of the demand cases. If the low or base case supply should occur, Canada's dependence on imported oil would increase over the forecast period. Even in the modified base case for supply, oil imports would be required unless demand conforms to the low demand case.

Figures 16-5, 16-6, 16-7 and 16-8 illustrate the components of the four supply cases and the three demand cases. These figures show the importance of new supply areas as production from established reserves declines over the forecast period. Although the rates of production forecast in the high case from oil sands, frontier areas, and enhanced oil recovery are considered unlikely to occur together, moderate increases in production in these three supply categories over those postulated in the modified base case could make Canada self-sufficient in oil by 1990.

Figure 16-9 shows the levels of imports and/or exports which could occur when comparing the middle case demand with both the base and modified base case supply. The two extremes of supply and demand are also shown. The comparison of the low supply and high demand shows how dramatically imports could grow over the forecast period reaching nearly 300 thousand cubic metres per day by 2000. Conversely, the comparison of high supply and low demand shows an optimistic balance in which Canada would have a surplus of crude oil by 1990.

16.1.2 *Heavy Crude Oil Exports*

Views of the Board

Figure 16-10 shows the forecast of supply of heavy crude oil for the base case and the refinery requirements based on the Board's middle case demand. The figure also shows the reduction in heavy crude oil supply if upgrading facilities were installed in 1988. These forecasts show that Canada will have an excess of heavy crude oil until upgrading facilities are constructed. A similar comparison in Figure 16-11 shows the forecast of supply of heavy crude oil for the modified base case and the refinery requirements based on the Board's middle case demand. The figure also shows the reduction in heavy crude oil supply if upgrading facilities were installed in 1986.

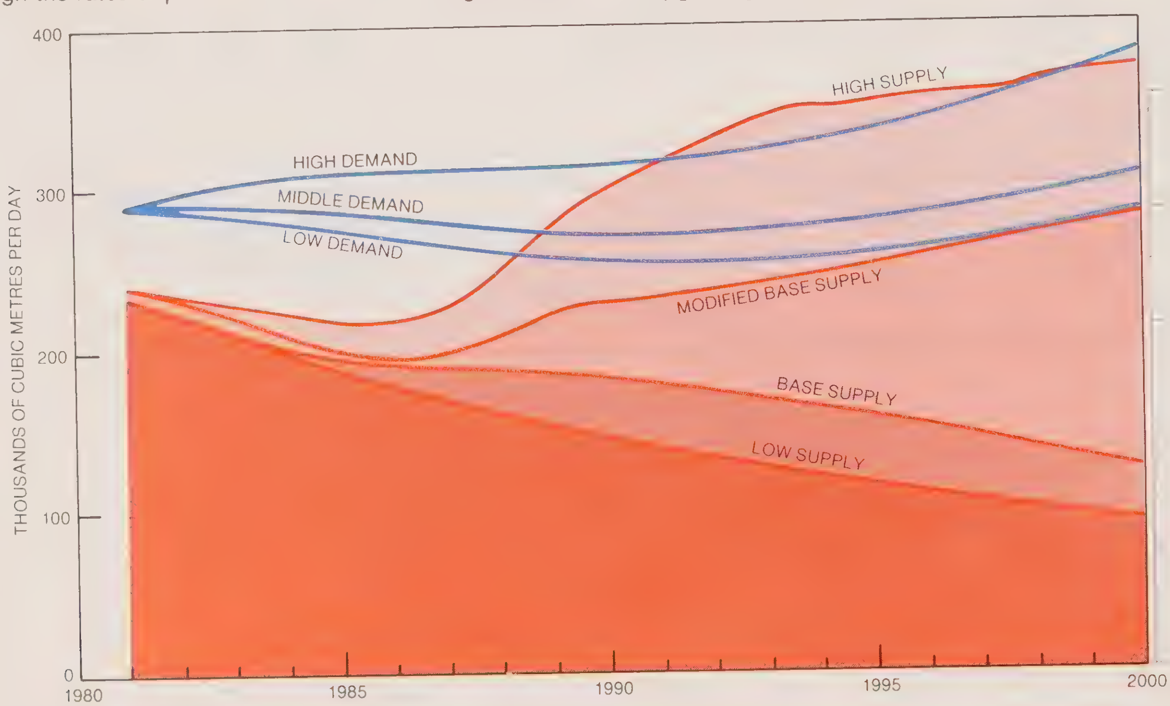

Figure 16-4 Supply & Demand - Crude Oil & Equivalent
Low, Base, Modified Base and High Supply
with Low, Middle and High Demand

Heavy crude oil exports have been relatively large and in 1980 were some 15 thousand cubic metres per day. It has been the Board's practice since the inception of separate licensing of heavy crude oil in January, 1977 to authorize the export of the full volumes of heavy crude oil available in excess of current domestic requirements. Consequently, production of heavy crude oil has generally been maintained at levels unrestricted by requirements, thus enabling producers to maximize revenue from these sources. Canadian refiners have had access on a monthly basis to all heavy crude oil volumes required while United States customers have had to adjust to changes in volumes available for export.

The Board is aware of the potential for production of domestic heavy crude oil to provide an increasing proportion of domestic supply. The Board is also aware of the need for producers to have access to stable markets for heavy crude oil production in order to sustain its development. In the near term, it will be necessary to continue to export surplus heavy crude oil to United States markets; in the longer term, however, the upgrading of heavy crude oil would permit more heavy crude oil to be used domestically. Nevertheless, even with heavy crude oil upgrading facilities in place, it may be desirable to export heavy crude to accommodate Canadian seasonal demand patterns for heavy crude oil and to permit phase-in of producing and upgrading facilities. The Board will continue to monitor the procedures for the licensing of heavy crude oil so that heavy crude oil development will not be inhibited.

Background data for Figures 16-10 and 16-11 can be found in Table 9-3. The table and graph are based on yearly average volumes but since requirements vary considerably by season, the full need to balance supply and requirements through export is not apparent from these illustrations.

16.1.3 *Other Related Matters*

Views of the Board

Light Crude Oil Exports

Light crude oil exports were essentially terminated in November 1979 when domestic requirements for these grades began to exceed available supply. At present only very small quantities are being exported from isolated wells on the Alberta-Montana border.

Crude Oil Exchanges

Export of Canadian light crude oil to Northern United States refiners in return for similar quality imports into Ontario and Québec has in the past few years formed an integral part of oil supply arrangements for the two countries. Although exchange volumes have now fallen to some 13 thousand cubic metres per day from a peak in 1979 of 21 thousand cubic metres per day, largely as a result of lower United States oil demand, these arrangements may continue to be beneficial to both countries. Exchanges have been entered into mainly to overcome transportation constraints but also to help fit specific crude oil qualities to refineries that could make the best use of them.

The level of exchanges is affected by United States market conditions including demand for refined petroleum products. Higher United States prices and elimination of government programs have diminished United States requirements for Canadian oil exported under exchange arrangements. Changes in Canada such as the use of greater volumes of condensate in Alberta and possible changed use of pipelines may also affect Canadian companies' ability to deliver export volumes under exchange.

Domestic Crude Oil Allocation

Since November 1979, Canadian demand for domestic light crude oil and equivalent has been such that formal allocation is required to prevent price distortions and to provide equitable distribution of the available supply. The Board after making allowance for requirements in the Western provinces and for the export of heavy crude oil, allocates the remaining domestic crude oil and equivalent to Ontario and Québec refineries. Allocation is controlled by the issuance of licences to export domestic oil at Gretna, Manitoba, for return at Sarnia via the Lakehead and IPL pipelines. Allocation is based on historical runs of crude oil in the refineries affected, with allowance made for processing arrangements by some Canadian wholesalers. To control more effectively the distribution of domestic crude to Montreal refineries, the Board, from 1 January 1980, has assumed responsibility for allocation of space on the Sarnia/Montreal section of the IPL pipeline, a function which up to that date had been carried out by the Petroleum Compensation Board.

As part of these allocation procedures, the Board introduced procedures designed to recognize the special needs of the small independent petroleum marketers in Eastern Canada. The approach, which the Board believes must remain flexible in order to meet changing circumstances, involves the issuance of allocations of domestic crude oil to new shippers. In order to obtain special allocation, the shipper must satisfy the Board that the company has a need for the oil.

The allocation of domestic crude oil puts limitations on crude oil users in their access to and purchase of domestic light crude oil and hence petroleum products markets. Companies wishing to obtain incremental supplies have to rely on importation of crude oil or finished product, wholesale purchase of finished products, or where yield patterns permit, incremental processing of domestic heavy crude oil.

Crude Oil Purchase Arrangements

It is important to recognize when discussing supply/demand balances that small fractional changes to total supply or demand can result in wide variations to the balance. Importers' efforts and ability to efficiently secure oil supplies to balance their base domestic supply and total requirements require continuous attention and coping with uncertainty. About a half-dozen major importers are involved in this balance process.

In the recent past, planning of crude oil purchases has been complicated by the Board's allocation of domestic crude oil, government sponsored imports (from Mexico) and cutbacks of domestic crude oil production. In the future, it can be expected that the off-oil program will further restrict refiners' ability to balance supply and requirements for individual petroleum products.

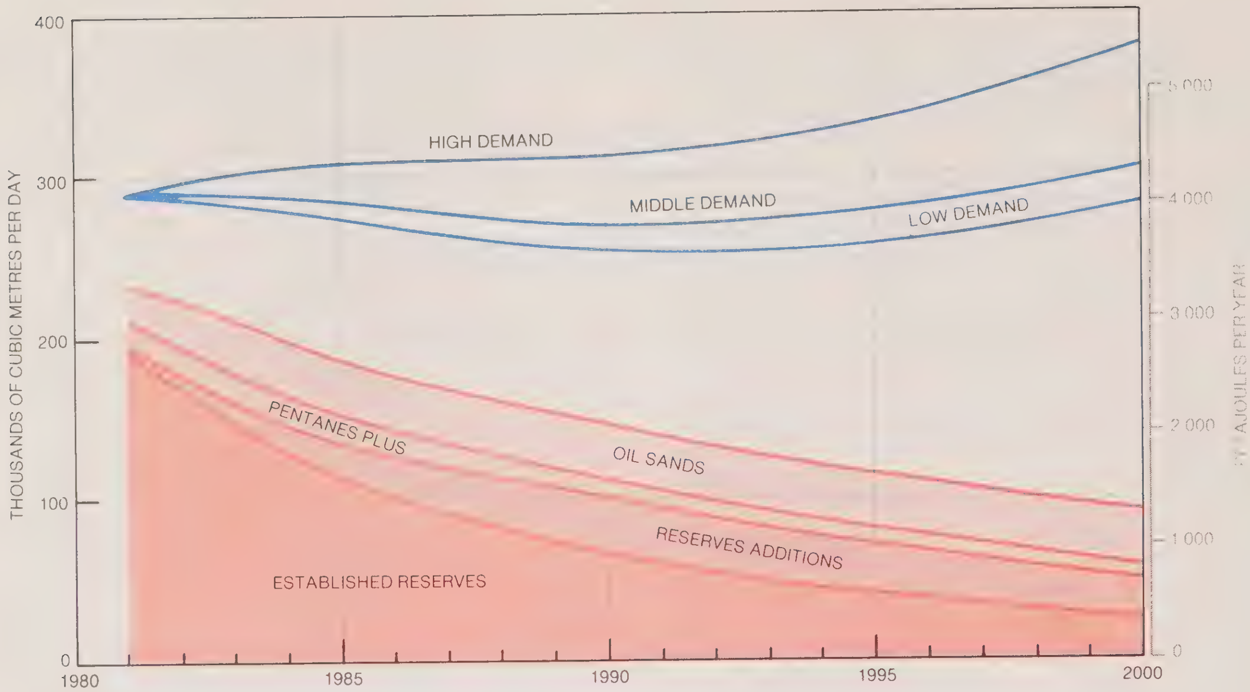

Figure 16-5 Supply & Demand - Crude Oil and Equivalent
Low Supply with Low, Middle and High Demand

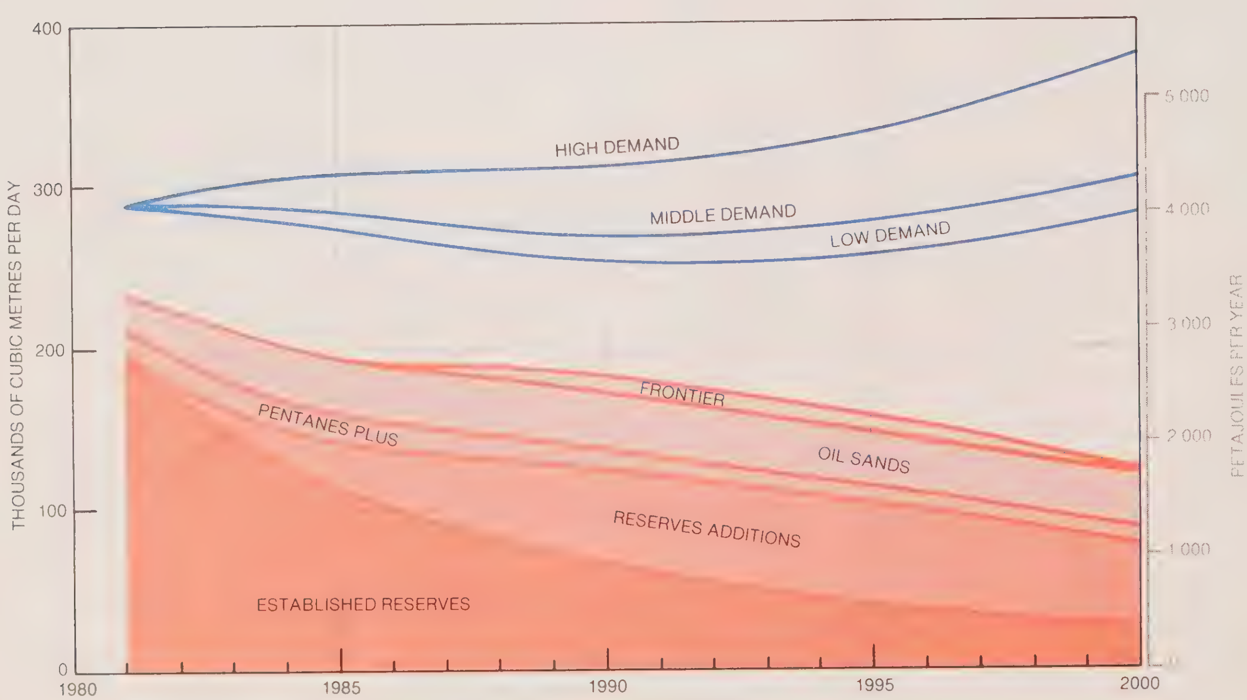

Figure 16-6 Supply & Demand - Crude Oil & Equivalent
Base Supply with Low, Middle and High Demand

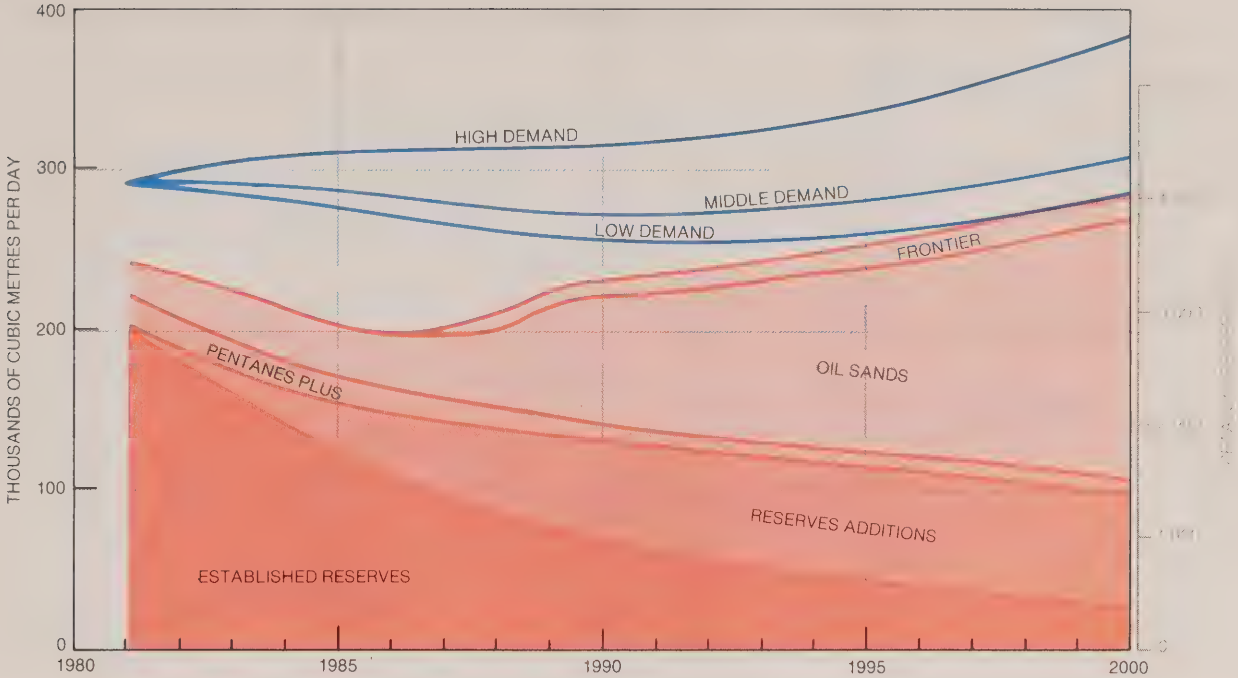

Figure 16-7 Supply & Demand - Crude Oil & Equivalent
Modified Base Supply with Low, Middle and High Demand

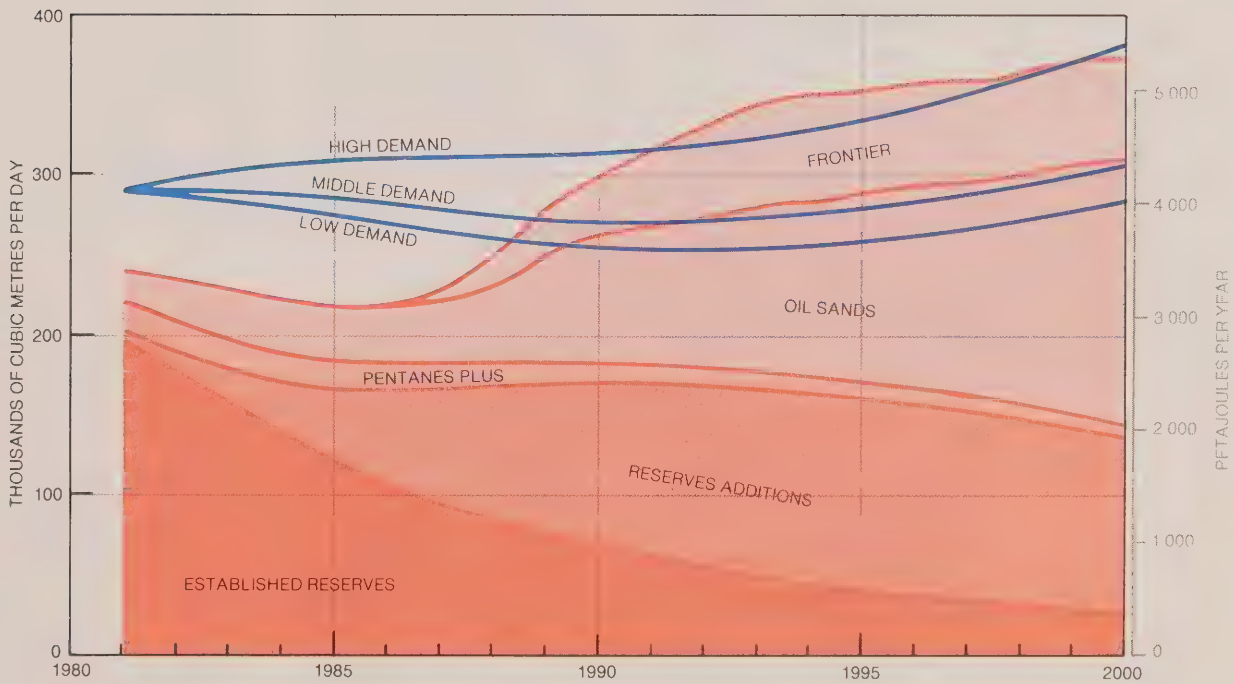

Figure 16-8 Supply & Demand - Crude Oil & Equivalent
High Supply with Low, Middle and High Demand

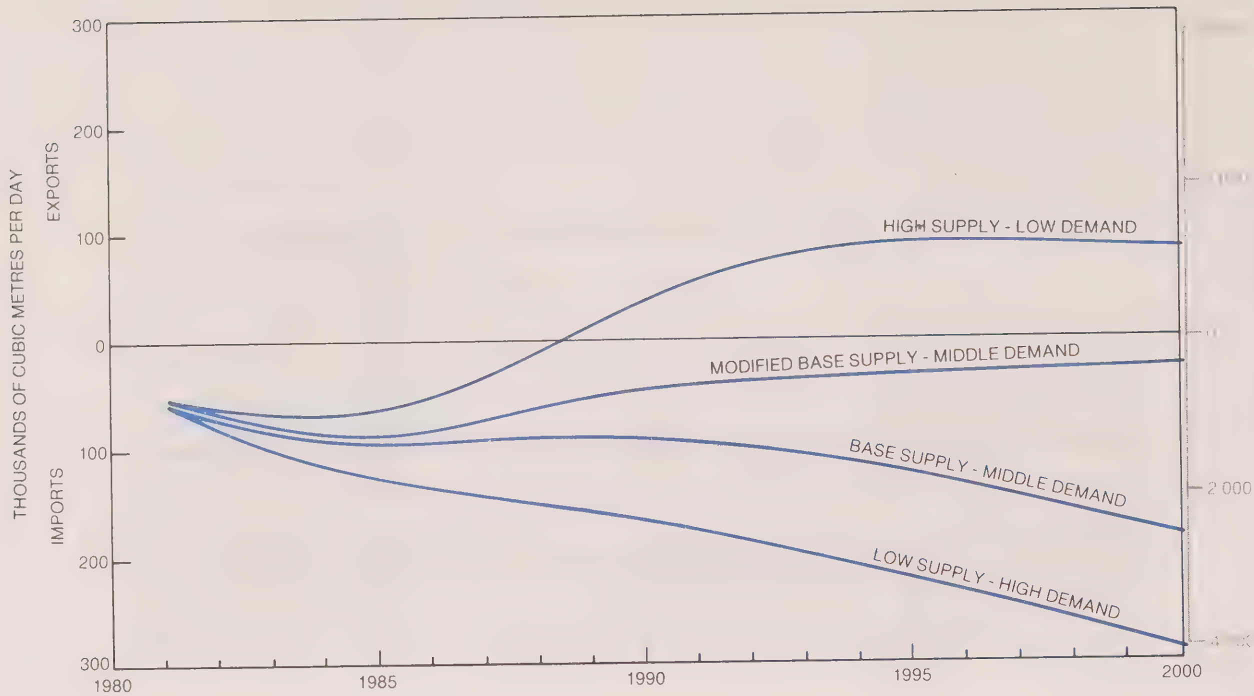

Figure 16-9 Net Imports/Exports - Crude Oil & Equivalent

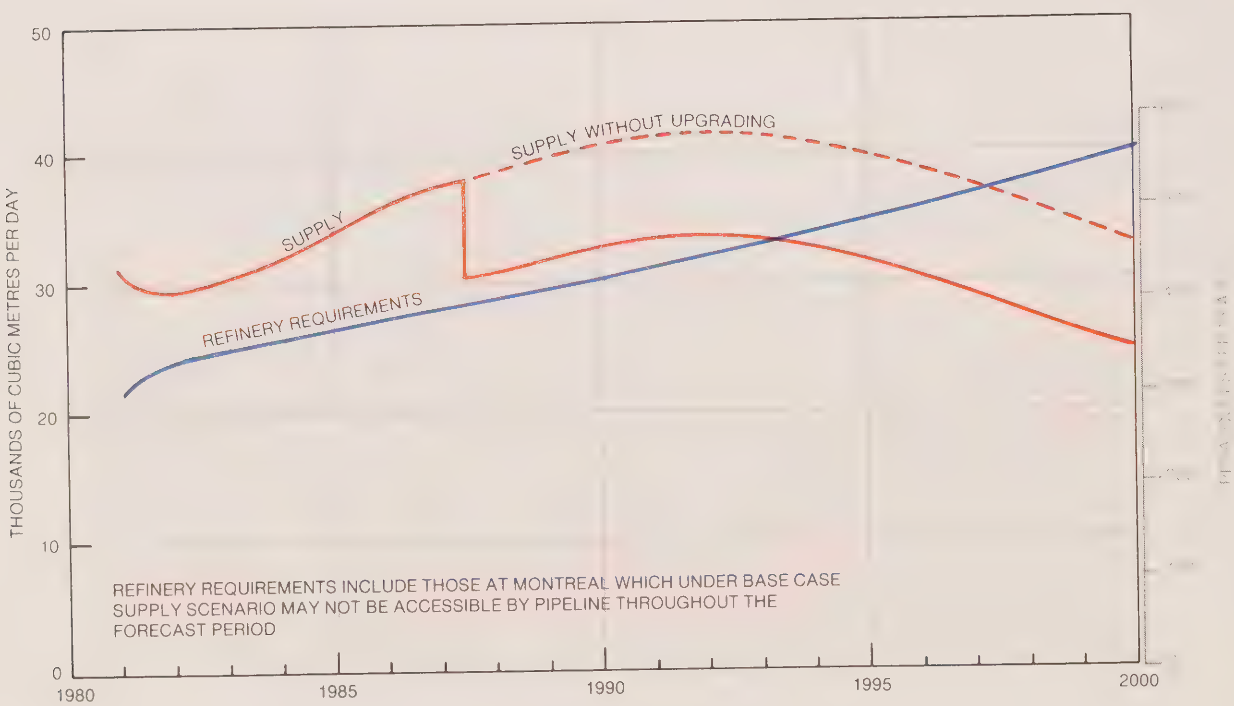

Figure 16-10 Supply & Demand - Heavy Crude Oil Base Supply with Middle Demand

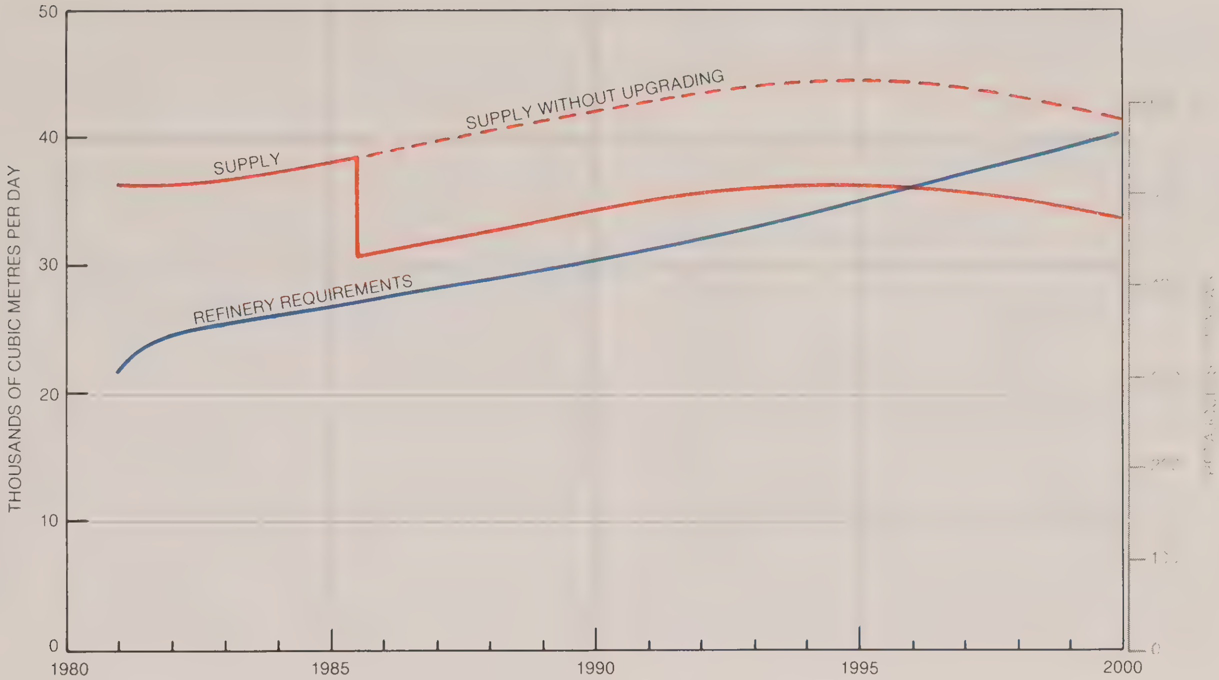

Figure 16-11 Supply & Demand - Heavy Crude Oil
Modified Base Supply with Middle Demand

Constraints of this kind may make some aspects of oil supply planning more certain, however, variations that inevitably occur tend to be more and more concentrated on the remaining volume of oil that is purchased in foreign markets and imported into Canada. In such circumstances, it can become difficult for refiners to commit to fixed term purchases of offshore supply so that greater reliance on spot purchases of crude oil or petroleum products could become necessary.

16.2 Natural Gas Balance

Views of Submittors

Most Submittors who provided estimates of potential productive capacity from reserves in the conventional areas of Canada also submitted a supply/demand balance. Some of the balances were simply overlays of the projected productive capacity and the expected demand forecasts. Other balances considered the effect that available gas not produced in the early years would have on the productive capacity in later years. Only a few submissions provided a tracking of demand by supply. Some of the Submittors also provided their views on natural gas surplus and these views are summarized in this section.

Amoco submitted that increased deliverability which would be attributed to appreciation of current reserves should be included in the Current Deliverability Test. Amoco recommended that the Current Deliverability Test should only be used as a check on security of supply and not as a means of quantifying the surplus since the test resulted in a large inventory of shut-in gas.

CARC pointed out that current forecasts indicated no domestic need for frontier gas until the turn of the century and any frontier project starting operations before then would therefore have to allow for exports. It stated that the issues raised by the impending development of frontier gas implied that the NEB export formulas might have to be revised to include a fourth test to ensure that the selling price of the gas being exported was higher than its replacement cost.

Canadian Hunter stated that the majority of gas was purchased under reserves based contracts and that the only true surplus calculation that could be made should be based on reserves. Deliverability was stated to be strictly a function of producer economics and if the appropriate markets and level of netback were there, deliverability would be there. Canadian Hunter added that the Current Deliverability Test was much too onerous for producers and should be discarded.

CPA offered a graphic illustration of its supply and demand projections to the year 1990, without attempting to track demand with supply. CPA's projections indicated that supply would exceed demand beyond 1990.

Consolidated prepared three supply/demand balances. Since Consolidated considered it reasonable for frontier gas to become available during the forecast period, the total demand projected was reduced in each case, by the corresponding levels of frontier production. The resulting net demands were then used in the supply/demand balances. Deficiencies first occurred in 1999 in the low case and in 1997 in the most likely case. No deficiency was expected in the high case.

Consumers' Gas stated that it was satisfied with the Board's surplus calculation procedure but advocated a conservative assessment of supply and a liberal estimate of requirements when the Board applied its three tests.

Dome stated that a comparison of conventional supply capability and domestic requirements showed a large surplus supply capability throughout the forecast period 1980-2000. Based on the NEB Current Reserves Test, Dome estimated that a total of 31.0 exajoules of natural gas, surplus to both Canadian demand and currently approved exports, would become available for export in the period 1980-2000.

Gulf presented three supply/demand balances for British Columbia, Alberta and east of Alberta including frontier sources, and total Canada, respectively. It felt this was a necessary refinement because certain pipeline and contractual restrictions were present which resulted in a surplus in one area with a deficiency in the other. This approach resulted in sufficient supply to meet demand throughout the forecast period. Gulf's forecasts illustrated that Canada was likely to have a surplus of natural gas available for export during the period 1986-2000. Gulf estimated that the NEP would reduce the volumes of surplus gas available for export.

Home stated that, provided Canadian interests were adequately protected, the short-term export of natural gas to the United States was the most practical solution in marketing the surplus of Canadian natural gas. The generated cash flow would allow the search for new supplies of conventional oil and gas and the development of non-conventional oil production.

As a result of limited market opportunities, Home stated that about 50 percent of its total proven, probable and potential gas reserves were shut-in. Unless steps were taken to provide immediate markets for the surplus of Canadian natural gas, a significant downturn in industry activity was likely to occur in the near future.

IPAC submitted that the Current Deliverability Test adopted by the Board was completely unnecessary and that, although it restricted markets, it did not protect Canadian consumers. IPAC recommended that the Board should discard the Current Deliverability Test and give consideration to longer licence periods.

Norcen stated that natural gas supply from Western Canada would be sufficient to meet existing exports and growth in Canadian demand until after the year 2000. Furthermore, Norcen stated that production from existing reserves was sufficient to meet total demand until 1990, if unused current deliverability in the years 1980-1985 were rolled forward until required. Norcen believed that over the 1980-2000 period, the NEP would cause the surplus of natural gas deliverability to decline by a maximum of some 340 petajoules per year in the year 2000 or by an average of 200 petajoules per year over the forecast period. This reduction was divided equally between lower natural gas supply and higher natural gas demand. Norcen recommended that a major effort should be made to develop new markets quickly to reduce surplus and avoid long shut-in periods which would have a strong impact not only on gas exploration but also on oil discoveries.

NOVA prepared current and future supply/demand balances with and without the APP export for both its scenarios. For the base case, using the established reserves, the first year of deficiency was 1994 and with the APP export included was 1993. The first year of deficiency using future supply including reserves additions in all cases was beyond the year 2000. Similarly, for the low case using established reserves, the first year of deficiency was 1991 and with the APP export included was 1988. The first year of deficiency using future supply was again beyond the year 2000. NOVA stated that its low case was a reasonable approximation of the impact of the price schedules set forth in the NEP. In its base case, a surplus of 17.4 exajoules was indicated while in its low case a surplus of 17.1 exajoules was indicated.

Imperial presented its forecast of total natural gas supply with and without frontier sources along with its estimate of domestic and authorized export demand. Its assessment indicated that the Southern Basin reserves alone could meet Canadian demand plus authorized export until after the year 2000. Imperial also stated that the export volumes surplus to Canadian needs would provide stimulus to the economy, help maintain a strong petroleum development program, and aid the balance of payments in a period of increasing oil export costs.

IGUA supported some additional exports within the export surplus determined by the Board's three tests. IGUA stated that it did not support the use of exports to finance exploration and development of more gas for export in an unending cycle.

ICG maintained that gas reserves surplus to requirements should be used to continue existing export licences in those areas currently franchised for a period of time to be determined by the Board. Gas reserves in excess of requirements should be assigned to both new Canadian and export markets. New exports should aid in the expansion of new Canadian markets.

Pan-Alberta submitted that the Current Deliverability Test used by the Board was deficient and limited any surplus determination to a very short term. Pan-Alberta felt the test disregarded problems created in financing new pipeline facilities and producer financing. The mechanics of the test were stated to be too complicated. Pan-Alberta recommended that the Board should use only the Current Reserves Test.

Panarctic recommended that a fraction of Arctic reserves should be included in the Current Reserves Test and that deliverability from those reserves should be included in the Current Deliverability Test.

Petro-Canada presented an illustration of natural gas supply and requirements. It stated that deliverability from conventional areas would meet projected Canadian requirements and currently authorized exports throughout the forecast period with a small deficiency commencing in the year 2000. Petro-Canada stated that additional export quantities might be possible under the existing NEB surplus test.

ProGas prepared supply/demand balances with and without future reserves additions. It demonstrated that without new reserves additions, supply and demand could be in balance until

1991. With future reserves additions the balance might be extended to 1999. ProGas expressed the opinion that in making a surplus determination the Board should make its best estimate of what the actual export demand will be as opposed to setting aside the allowed limit of annual export.

Manitoba believed that the addition of two deliverability tests to the reserves test improved deliverability protection. However, Manitoba felt that the absolute level of long-term protection had diminished, given the change in the Current Reserves Test, when the potential for increased gas consumption in Canada was considered.

SPC expected that through new exploration and development, an unspecified supply of natural gas would balance demand in Saskatchewan for the period 1980-2000.

Shell presented a comparison of its supply and demand forecast which included an adjustment to the deliverability potential to account for the unused deliverability in the early years. This comparison demonstrated that supply would meet projected domestic and currently authorized export requirements throughout the forecast period. Under the NEP, Shell indicated that deficiencies would first occur in 1997. Shell proposed that frontier gas should be considered in the supply base, after the Board was satisfied the transportation means would be constructed.

Texaco's forecast of supply and demand indicated significant surplus deliverability throughout the forecast period. Despite an accelerated use of natural gas in Canada, Texaco forecast a large exportable surplus during the forecast period.

TCPL prepared a supply tracking demand forecast from established reserves only, and additional balances using both its low and high trend forecasts. The first year of deficiency using only established reserves was 1993 while both balances which included reserves additions demonstrated surplus supply throughout the forecast period. TCPL also prepared three supply/demand balances which reflected its assessment of the impact of the NEP on both supply and requirements. Its first supply/demand balance from currently established reserves indicated that deficiencies would commence in 1985. The second balance assumed limited markets with no changes to the NEP, while the third assumed adequate incentives through a combination of market opportunities and/or modifications to the NEP. Both the second and the third balances, which included supply from trend additions, demonstrated surplus deliverability throughout the forecast period. TCPL recommended that the NEB should modify the surplus test procedures or face the inevitability of a downturn in the industry activity. TCPL felt that this possibility would not be conducive to meeting Canada's national goals of long-term energy self-sufficiency.

TCPL's proposal was to amend the test so that in the first year, 90 percent of trend gas would be included, decreasing by ten percent per year so that in the fifth year, 50 percent of trend gas would be given the same recognition as proven reserves. TCPL further stated that the current deliverability test in its existing form limits markets that could be attached to relieve the shut-in gas surplus, and such market limitation then would act as a disincentive to attach shut-in gas and create deliverability.

16.2.1 *Reserves and Deliverability Tests*

Views of the Board

The Board, in its 1979 Gas Report discussed in detail the matter of the determination of surplus gas within the meaning of Section 83 of the National Energy Board Act.

The Board concluded that the procedure for the determination of surplus should rely both on deliverability tests and on a reserves test.

The Board believed that a test utilizing deliverability from established reserves, that is, a Current Deliverability Test, would provide the requisite high degree of assurance that Canadian demand and authorized exports would be met. The Board believed that this period of highly assured protection should be a minimum of five years.

The Board also felt that a reserves test was necessary to maintain a reasonable relationship between reserves and deliverability. The Board believed that tests solely relying on deliverability could lead to excessive industry activity to increase deliverability at the expense of developing new reserves. The Board decided that a suitable amount of protection would be afforded by setting aside established reserves to provide coverage of current Canadian demand for a period of 25 years plus authorized exports.

The Board also believed it was important to ensure that requirements are protected not only for a minimum of five years under the Current Deliverability Test, but also for a longer period from a combination of established reserves, reserves additions, and, when appropriate, new sources of gas such as frontier reserves.

The Board considered that established frontier natural gas reserves, additions to those reserves and deliverability from those reserves, should be included in the Board's calculation of surplus under the Reserves and Deliverability Tests only at such time when those reserves are believed to be within economic reach. The Board did not believe it to be appropriate to include frontier reserves until transportation facilities have been authorized and the Board is satisfied that those facilities will be constructed. At the present time, none of the frontier reserves meet these criteria.

Although some evidence was presented at this hearing indicating that the Current Deliverability Test should be modified or abandoned, the Board is not prepared to change the procedure at this time.

The Board has calculated its three surplus tests for illustrative purposes using the middle case demand, the supply from established reserves, the allowance given existing licences and the deliverability from the base case reserves additions.

Current Reserves Test

The Current Reserves Test, calculated as of 31 December, 1980, is tabulated in Table 16-1.

Current Deliverability Test

CAPABILITY

The maximum level of deliverability from established reserves (i.e., capability), unrestricted by demand, is shown on Figure 16-12.

TRACKING EXISTING DEMAND

Estimated deliverability from established reserves is used to track or meet estimated annual Canadian requirements plus authorized exports as shown in Table 16-2, Appendix V and on Figure 16-12.

Future Deliverability Test

CAPABILITY

Production at the maximum level of deliverability from established reserves and the base case reserves additions is shown on Figure 16-13.

Table 16-1

CURRENT RESERVES TEST
(Exajoules)

	As of 31 Dec. 1980	
Remaining Established Reserves[1]	76.2	
Less Deferred Reserves[2]	1.3	
Less One-half of Reserves Beyond Economic Reach[3]	0.8	
Less Processing Shrinkage[4]	4.7	
Total Supply		69.4
Canadian Sales[5]	45.7	
Authorized Export Sales[6]	14.4	
Total Requirements (including pipeline fuel)		60.1
Current Reserves Surplus (Total supply less total requirements)		9.3

Notes

[1] No allowance has been made for frontier reserves.

[2] The total deferred reserves in Alberta are estimated to be 3.5 EJ, with 2.2 EJ expected to be connected within 25 years.

[3] Beyond Economic Reach reserves are estimated as 1.6 EJ for Alberta and negligible for British Columbia.

[4] Processing shrinkage is based on expected hydrocarbon removal at straddle plants.

[5] Canadian Sales include pipeline fuel and losses but do not include fuel used for exports. They are 25 times the annual demand of 1.827 EJ for 1981.

[6] Authorized Export Sales includes all currently authorized licenced exports estimated to be remaining on 31 December 1980 plus an allowance of 0.4 EJ for fuel used in Canada to transport these quantities.

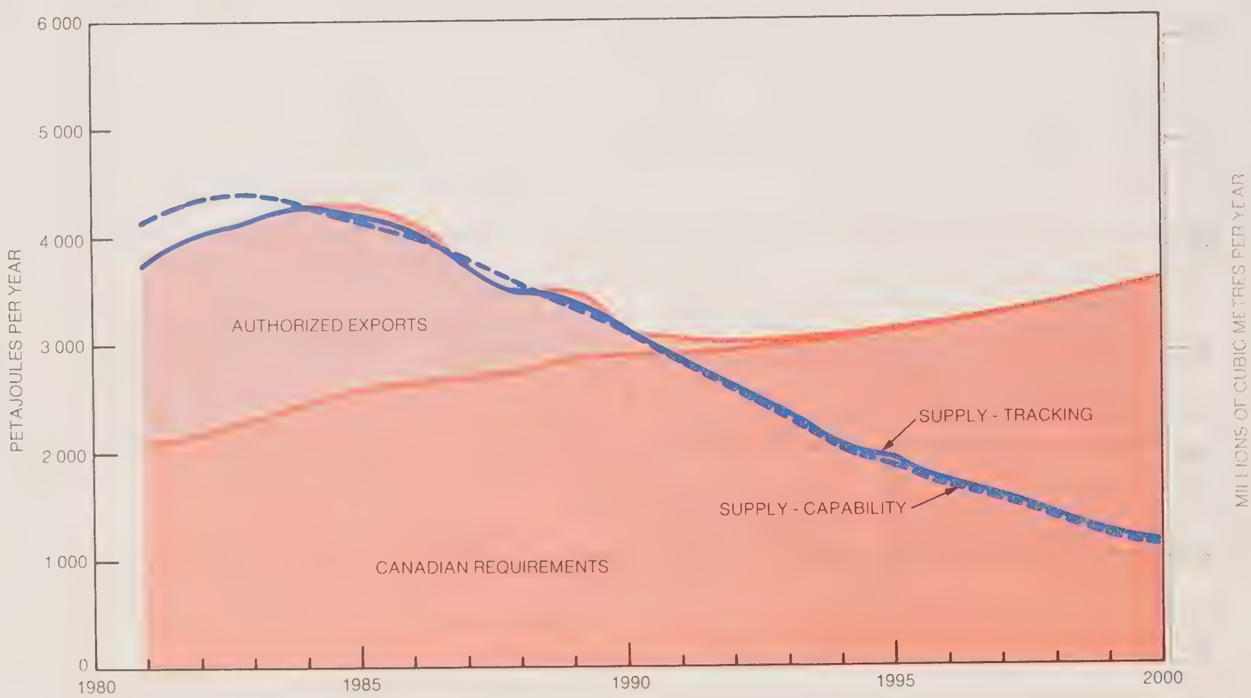

Figure 16-12 Current Deliverability Test
Canadian Requirements plus Authorized Exports

Table 16-2

CURRENT DELIVERABILITY TEST
(Petajoules/yr)

Year	Domestic Demand	Export Demand	Total Demand	Supply Capability	Surplus	Supply Tracking	Deficiency
1981	2 076	1 675	3 751	4 133	382	3 751	0
1982	2 157	1 863	4 020	4 348	329	4 020	0
1983	2 304	1 845	4 150	4 412	263	4 150	0
1984	2 455	1 843	4 298	4 301	3	4 298	0
1985	2 572	1 736	4 308	4 139	–169	4 196	112
1986	2 633	1 484	4 117	4 015	–102	4 082	35
1987	2 691	1 083	3 773	3 782	9	3 773	0
1988	2 750	751	3 501	3 585	84	3 501	0
1989	2 855	642	3 498	3 338	–160	3 417	80
1990	2 874	244	3 118	3 127	9	3 116	2
1991	2 897	145	3 043	2 836	–206	2 870	173
1992	2 943	62	3 005	2 588	–417	2 642	363
1993	2 989	54	3 043	2 325	–718	2 388	654
1994	3 062	14	3 075	2 027	–1 048	2 082	994
1995	3 143	11	3 155	1 853	–1 301	1 924	1 231
1996	3 214	0	3 214	1 680	–1 534	1 740	1 474
1997	3 281	0	3 281	1 567	–1 714	1 608	1 673
1998	3 374	0	3 374	1 386	–1 987	1 432	1 941
1999	3 475	0	3 475	1 229	–2 246	1 269	2 206
2000	3 585	0	3 585	1 117	–2 468	1 158	2 427

TRACKING EXISTING DEMAND

Estimated deliverability from established reserves and from reserves additions is used to track or meet annual Canadian requirements plus total authorized exports as shown in Table 16-3, Appendix W and on Figure 16-13.

Based on the Current Deliverability Test tracking case the Board concludes that established reserves as of 31 December 1980 meet the estimated annual Canadian requirements plus authorized exports up to 1985 when a deficiency of 112 petajoules occurs. A small deficiency occurs in 1986 and a deficiency of 80 petajoules occurs in 1989 and the deficiencies grow continuously after 1990.

The capability curve indicates that surplus deliverability of about 1.0 exajoules, based on established reserves, could be available in the years 1981 to 1984 inclusive and that deliverability deficiencies of the order of three to five percent of total demand could occur during the period 1985 to 1990 inclusive if this surplus deliverability was used.

While there is surplus deliverability under the capability curves, the five year period of assured protection is not satisfied. The tracking case indicates that unless there was some adjustment to the existing licences in 1985, no additional export licences could be granted at this time.

The Future Deliverability Test indicates that surplus deliverability could be available during the period 1981 to 1995 inclusive.

It is important to note that all exports were protected up to the volumes authorized in the licences, although in recent years, volumes of exports have been considerably below the authorized levels.

Although the Current Deliverability Test is now the limiting test and will continue to be the limiting test, for the next few years, the Board expects that, based on the current supply and demand situation, in the not too distant future, the Current Reserves Test and/or the Future Deliverability Test might well be the limiting test when considering the matter of surplus.

16.2.2 *Supply/Demand Balance*

Views of the Board

In order to show the sensitivity involved in the natural gas supply/demand balance, the Board has used its three demand cases and three supply cases to illustrate when additional supply may be required to satisfy Canadian demand assuming the existing export licences are fully protected.

Figure 16-14 illustrates the low, middle, and high demand cases and the low, base, and high cases showing supply capability. This figure illustrates how the supply could be delivered if markets were available.

In order to illustrate the effect of possible supply from the frontier area, Figure 16-15 shows the base case supply plus an illustrative deliverability schedule from three frontier areas and the

Table 16-3

FUTURE DELIVERABILITY TEST
(Petajoules/yr)

Year	Domestic Demand	Export Demand	Total Demand	Supply Capability	Surplus	Supply Trackiing	Deficiency
1981	2 076	1 675	3 751	4 153	403	3 751	0
1982	2 157	1 863	4 020	4 416	396	4 020	0
1983	2 304	1 845	4 150	4 559	409	4 150	0
1984	2 455	1 843	4 298	4 566	268	4 298	0
1985	2 573	1 743	4 316	4 537	221	4 316	0
1986	2 638	1 550	4 188	4 541	353	4 188	0
1987	2 699	1 317	4 017	4 430	414	4 017	0
1988	2 774	1 100	3 874	4 351	477	3 874	0
1989	2 855	642	3 498	4 214	717	3 498	0
1990	2 874	244	3 118	4 105	987	3 118	0
1991	2 897	145	3 043	3 905	862	3 043	0
1992	2 943	62	3 005	3 734	729	3 005	0
1993	2 989	54	3 043	3 534	492	3 043	0
1994	3 062	14	3 075	3 288	213	3 075	0
1995	3 143	11	3 155	3 153	–1	3 155	0
1996	3 214	0	3 214	3 007	–207	3 214	0
1997	3 281	0	3 281	2 911	–370	3 281	0
1998	3 374	0	3 374	2 738	–636	3 114	259
1999	3 475	0	3 475	2 580	–895	2 952	523
2000	3 585	0	3 585	2 460	–1 125	2 834	750

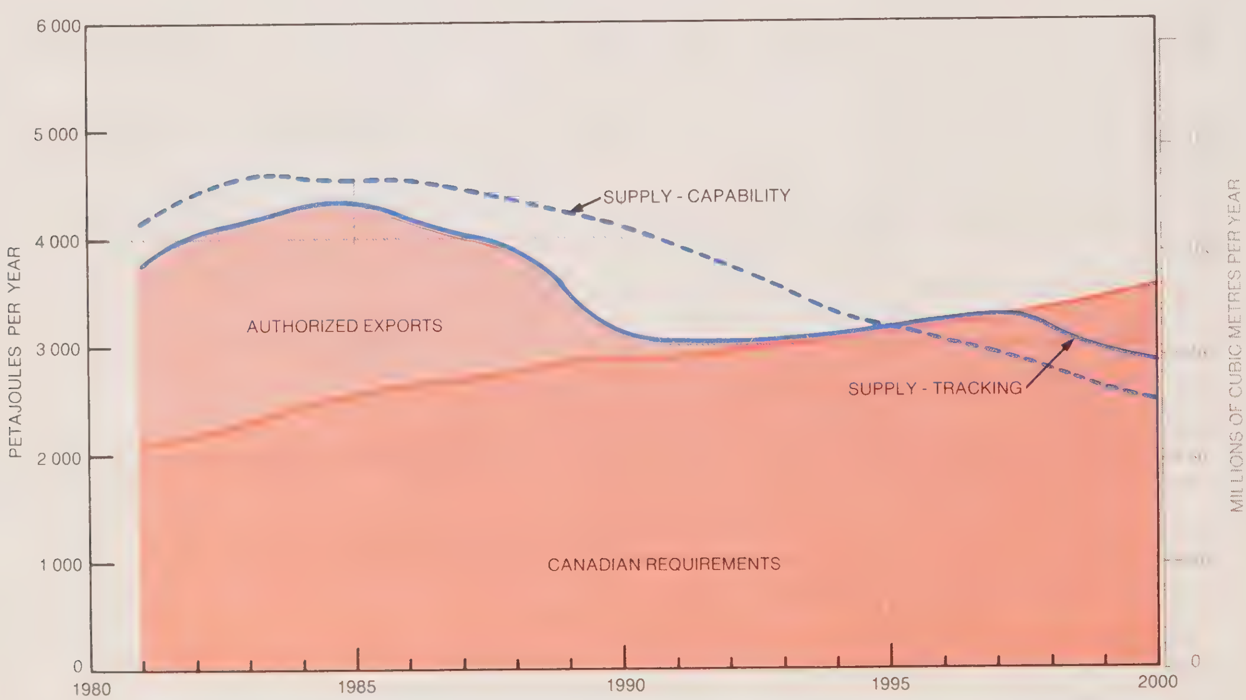

Figure 16-13 Future Deliverability Test
Canadian Requirements plus Authorized Exports

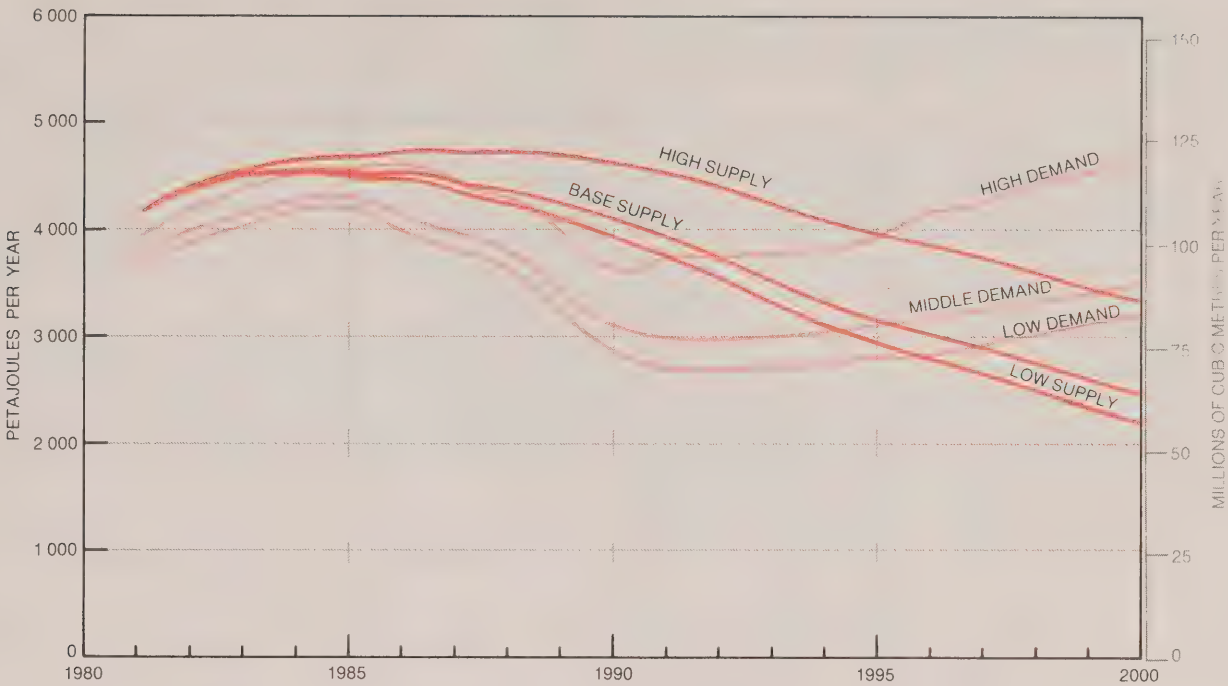

Figure 16-14 Supply & Demand - Natural Gas
Low, Base and High Supply Capability
with Low, Middle and High Demand

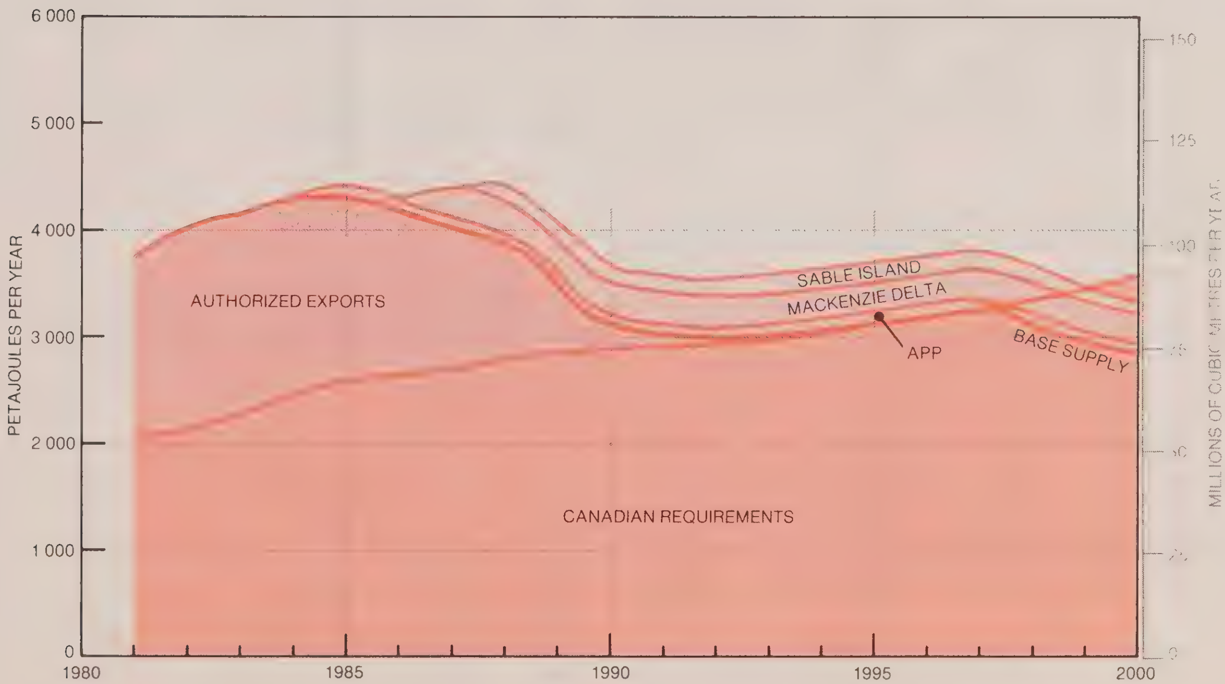

Figure 16-15 Supply & Demand - Natural Gas
Base Supply Tracking Middle Demand
Illustrating Frontier Supply

middle case demand. As can be seen from this figure, the Board does not expect that frontier supply of natural gas will be required for Canadian use before 1998 unless additional exports are allowed.

Figure 16-16 illustrates the ability of supply from established reserves plus the base case reserves additions to track or meet the three possible Canadian demand cases plus the allowance given to currently authorized export quantities. If the high demand case materialized, additional supply would be required in 1993, whereas for the low demand case, additional supply would not be needed until 1999.

Figure 16-17 illustrates the impact that the three supply cases would have on the supply/demand balance based on the Board's middle demand case plus the allowance given to currently authorized export quantities. If reserves additions were to materialize as forecast in the Board's low supply case, additional supply of natural gas would be required starting in 1996. Alternatively, for the high supply case, new sources of supply would not be required until beyond the forecast period.

Figure 16-18 illustrates the extremes that are possible in the supply/demand balance. The high supply forecast tracks the low demand well beyond the year 2000. The low supply forecast is unable to meet the high demand forecast in the mid-1980s but the differences are small and are unlikely to occur. Additional supply could be required as early as 1992 if the high demand and low supply cases occurred as projected.

16.3 Natural Gas Liquids Balances

Natural Gas liquids are generally produced either as by-products of natural gas processing and crude oil refining or as products of natural gas reprocessing. Thus, the supply of NGL depends to a great degree on the demand for crude oil and natural gas.

Views of Submittors

Dome expected that substantial volumes of ethane would be available for export throughout the forecast period. It also forecast that propane and butanes supply would exceed demand during the forecast period. With regard to pentanes plus, Dome forecast that there should be adequate supply for Alberta uses and for proper operation of the NGL system to Sarnia.

Husky anticipated a shortfall of pentanes plus for heavy crude diluent by the middle 1980s.

Petro-Canada forecast that ethane supply would exceed domestic demand during the forecast period. It also anticipated that domestic demand for propane and butanes would be substantially less than supply during the forecast period. It anticipated that large surpluses of butanes would be available for export.

Shell forecast that production of ethane, propane and butanes would be more than sufficient to meet projected demand. The resulting surpluses would be available for the export market or, in the case of propane, they could be used to meet any additional demand in the transportation sector.

Views of the Board

Table 16-4 summarizes the supply and demand of ethane as well as the licensed exports. The forecast shows a shortfall in ethane supply relative to total requirements in 1981. This shortfall is not expected to materialize, however, because full export quantities are not projected to be delivered in 1981. After 1985, ethane supply is forecast to be insufficient to meet total projected requirements. The ethane export situation is regularly monitored by the Board to ensure that Canadian requirements are satisfied.

Canadian propane supply and demand is summarized in Table 16-5. The forecast illustrates that Canadian propane supply is more than adequate to meet Canadian demand for propane until after 1985. Because of the termination of cycling schemes and the reduction in both solution gas and natural gas produc-

Table 16-4

ETHANE SUPPLY/DEMAND BALANCE
(Petajoules)

	Supply	Demand			Difference
	Total	Canada[1]	Net Licences Export	Total	
1981	94.7	44.4	58.6	103.0	–8.3
1982	108.4	44.4	49.8	94.2	14.2
1983	126.1	44.6	49.3	93.9	32.2
1984	162.5	57.3	48.5	105.8	56.7
1985	177.0	107.0	45.7	152.7	24.3
1986	177.4	140.8	50.8	191.6	–14.2
1990	145.1	147.9	14.2	162.1	–17.0
1995	124.8	140.1	0	140.1	–15.3
2000	91.9	135.8	0	135.8	–43.9

[1] Includes ethane used in miscible flooding.

Table 16-5

PROPANE SUPPLY/DEMAND BALANCE
(Petajoules)

	Supply	Demand			Difference
	Total	Canada[1]	Net Licences Export	Total	
1981	191.1	87.3	20.8	108.1	83.0
1982	207.7	87.9	19.9	107.8	99.9
1983	206.0	94.8	7.4	102.2	103.8
1984	209.9	95.4	7.4	102.8	107.1
1985	203.5	97.9	7.4	105.3	98.2
1990	151.6	158.0	6.7	164.7	–13.1
1995	138.3	181.4	0	181.4	–43.1
2000	130.6	183.7	0	183.7	–53.1

[1] ncludes propane used in miscible flooding.

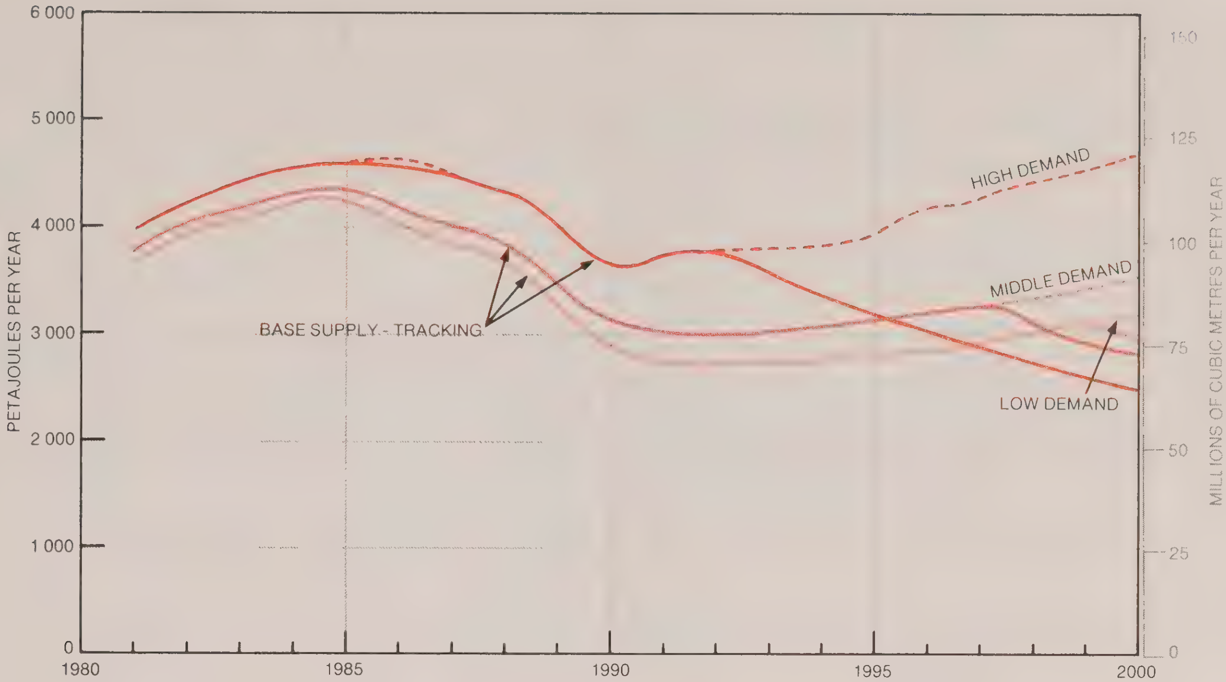

Figure 16-16 Supply & Demand - Natural Gas
Base Supply Tracking
Low, Middle and High Demand

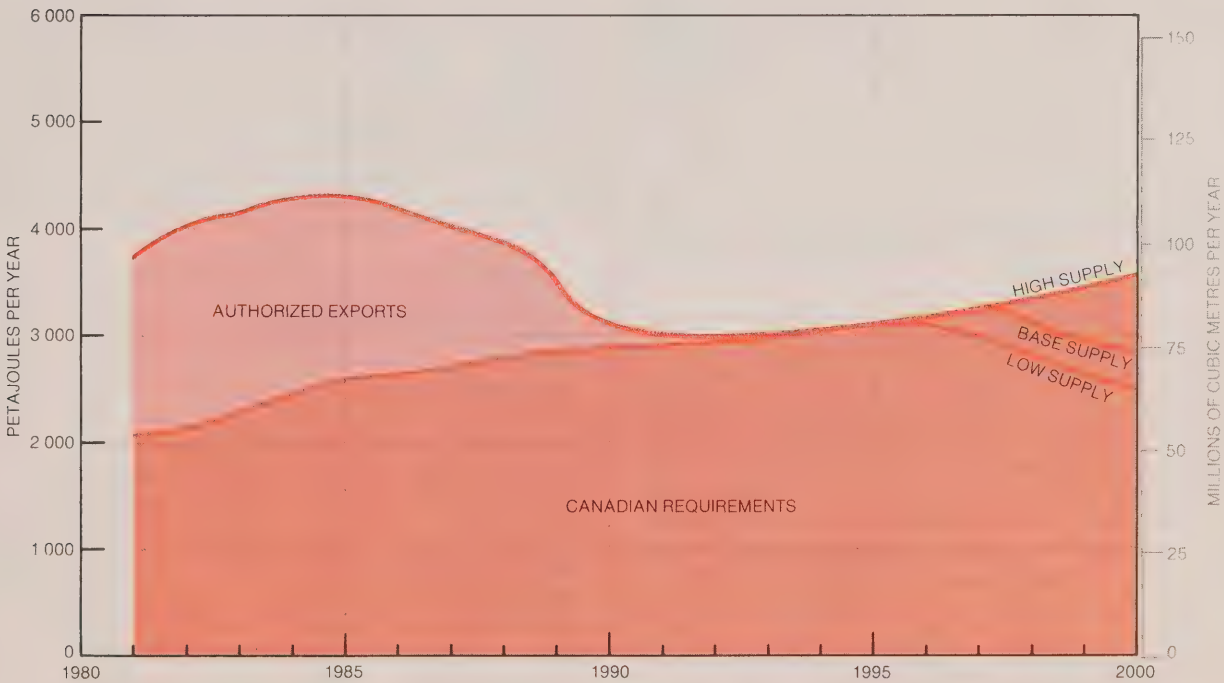

Figure 16-17 Supply & Demand - Natural Gas
Low, Base and High Supply Tracking
Middle Demand

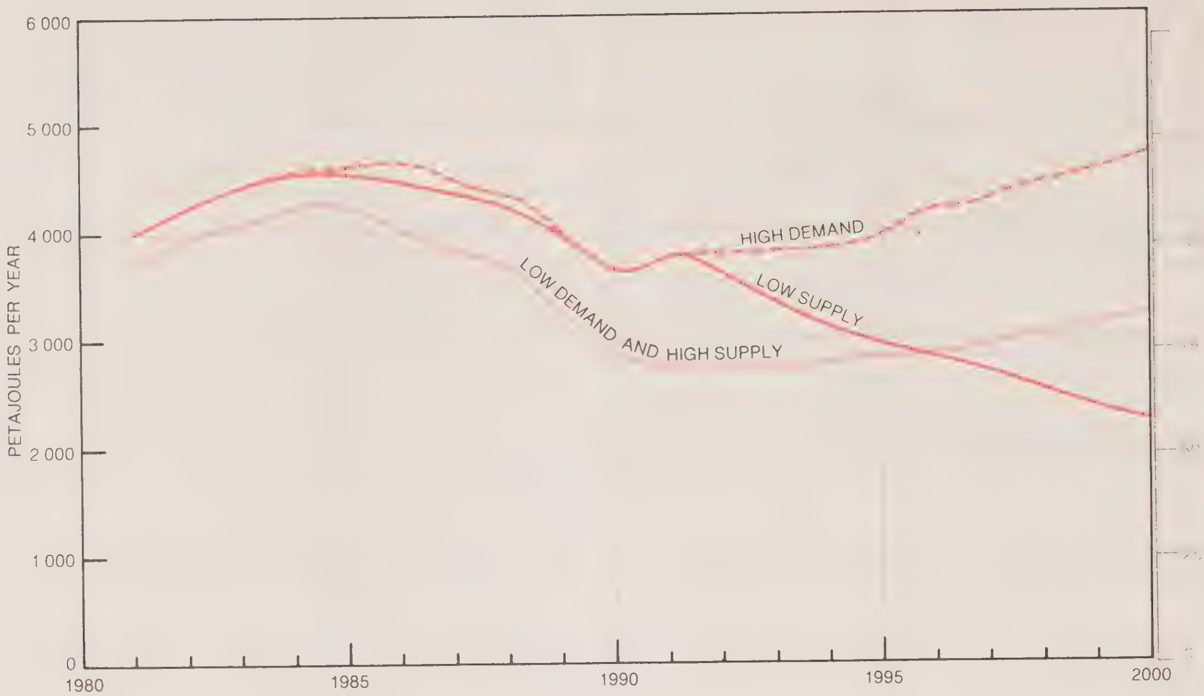

Figure 16-18 Supply & Demand - Natural Gas
High Supply Tracking Low Demand and
Low Supply Tracking High Demand

tion volumes, the supply of propane is expected to decline in the period 1985 to 1990 and reach a deficit position in the late 1980s. This deficit of propane is expected to increase in the 1990s if the demand for propane, mainly in the transportation sector, materializes as forecast.

Table 16-6 illustrates Canadian supply and demand for butanes. As for propane, Canada has a surplus of butanes in the near term. However, while this surplus is also forecast to decline, supply and demand are expected to be approximately in balance during the period 1990-2000.

Pentanes plus is a premium form of light crude oil and all available pentanes plus is currently used in existing refining and petrochemical facilities. The Board's forecast of pentanes plus supply has been summarized in Appendix M. The total volume of pentanes plus shown as supply is not fully available as segregated liquids because of geographic location and current blending practices with light oil. However, necessary modifications could be made to the existing transportation systems and light oil blending practices and nearly the full forecast volume of pentanes plus could be made available as segregated pentanes plus. Growth in the demand for pentanes plus for use as a heavy crude oil diluent, for miscible flooding, and for use as a petrochemical feedstock will only aggravate an already tight supply situation even if the full forecast quantities were made available.

The foregoing NGL supply/demand balances are based on the Board's base case supply and middle case demand forecasts. Under the assumptions on which those forecasts are based, there exists the possibility of shortfalls in the supply of ethane and propane in the later years of the forecast period. However, the Board is aware that additional NGL supply potential exists. The base case NGL supply does not include production of NGL from synthetic crude oil plants. However, given adequate markets and prices, facilities may be put in place to recover additional LPG. In the frontier areas, it was forecast that no LPG would be recovered. The possibility exists for the construction of

Table 16-6

BUTANES SUPPLY/DEMAND BALANCE
(Petajoules)

	Supply	Demand			Difference
	Total	Canada[1]	Net Licences Export	Total	
1981	132.5	68.6	0	68.6	63.9
1982	139.4	69.6	0	69.6	69.8
1983	142.0	70.4	0	70.4	71.6
1984	143.7	70.7	0	70.7	73.0
1985	139.3	69.6	0	69.6	69.7
1990	104.0	102.1	0	102.1	1.9
1995	95.7	89.9	0	89.9	5.8
2000	91.8	85.3	0	85.3	6.5

[1] Includes butanes used in miscible flooding and gasoline blending at refineries.

a natural gas reprocessing facility in British Columbia. This facility would provide feedstock to an associated petrochemical plant and could influence both the forecast supply and demand for NGL.

In summary, the Board is aware that the potential does exist for NGL supply shortfalls but is not certain that such shortfalls will materialize in view of the above considerations.

16.4 Electricity Balance

Since electricity cannot be stored, the question of balance between supply and demand is somewhat different from that for other fuel types. Under normal conditions electricity supply and demand are exactly in balance at all times. This implies that sufficient generating capacity is in place and operating, that fuel supplies are adequate, and that the necessary transmission and distribution systems are available. The evidence at the hearing indicates that Canadian utilities do not expect to experience undue difficulty in expanding their systems to meet growth in either peak load or energy demand. The Board is satisfied that ample coal, uranium, and some undeveloped hydro-electric sites will be available to generate electricity to meet existing and new loads. The only foreseeable constraint is the increasing lead times required for construction of new generation. If loads begin to grow dramatically, it could prove difficult to accelerate generation expansion programs as quickly. In the Board's view, it is very unlikely that a sudden change of sufficient magnitude to cause demand to outstrip supply will occur.

Canadian utilities experience their highest loads during the winter months. It follows naturally that where sufficient generating capacity is available to meet the peak demand, some surplus capacity will be available at other times of the year. Assuming sufficient supplies of fuel, this surplus capacity can be used to generate energy for delivery to other systems in Canada or to the United States. Exchanges between Canadian utilities are taken into account in the Board's determination of fuels used to supply electricity outlined in Chapter 13.

Table 16-7 presents an estimate of firm and interruptible electricity exports to the United States from 1980 to 2000. Offsetting imports are normally in the order of five percent of exports. The forecast is based on expected international transmission capacity, expected surpluses of hydro and other fuels, and anticipated American markets which can be economically served by Canadian exports. It assumes normal precipitation and temperature patterns in both countries. It does not include any schemes involving advancing or constructing generation explicitly for export purposes. The forecast can only be viewed as a rough estimate as actual exports will be determined not only by all the above factors but also by various intangibles such as regulatory attitudes, political considerations, environmental restrictions and international relations.

Of the 1980 exports, 48 percent were generated from hydro, 40 percent from United States coal (by Ontario Hydro), 10 percent from imported oil, and 2 percent from Canadian fuels including uranium. Over the forecast period, hydro and United States coal are expected to remain the predominant fuels for export generation. Neither oil nor gas is expected to contribute significantly after 1986 when EL-64, which authorized firm exports from NBEPC's oil-fired Coleson Cove generating station, expires. Canadian fuels, particularly coal, are expected to play an increasing role when utilities in Saskatchewan and Alberta enter the export market.

Exports of electricity are an important source of revenue and foreign exchange, amounting to almost $800 million in 1980. Although domestic electricity prices are expected to remain constant in real terms over the forecast period, it is expected that this will not be true of revenues from exports as export prices are linked to United States electricity costs as well as those in Canada. A significant proportion of United States generating capacity is oil-fired, particularly in the northeast, therefore it is expected that export prices will increase in relation to increases in international oil prices.

Table 16-7

FORECAST OF TOTAL ELECTRICITY EXPORTS TO THE USA (Petajoules)

	(Actual) 1980	1985	1990	1995	2000
New Brunswick	149	6	1	1	
Québec	29	45	67	51	27
Ontario	41	68	68	43	43
Manitoba	12	10	5	4	5
Saskatchewan	—	2	2	2	2
Alberta	—	1	1	6	8
B.C.	5	41	19	4	5
CANADA	101	176	168	111	91

APPENDICES

ORDER NO. EHR-1-80

IN THE MATTER OF the National Energy Board Act and Sections 14(2), 22(1) and 24 thereof; and

IN THE MATTER OF an inquiry into the supply of oil, natural gas, and other forms of energy in relation to the domestic demand for all forms of energy, and the supply/demand balances for hydrocarbons and electricity; under File Number 1045-3

B E F O R E the Board on Thursday, the 17th day of April, 1980.

WHEREAS the Board deems it advisable in the light of changing circumstances to make an appraisal of the supply of oil, natural gas, and other forms of energy in relation to the domestic demand for all forms of energy, and the supply/demand balances for hydrocarbons and electricity;

AND WHEREAS the Board finds it advisable to hold a public inquiry to afford the opportunity for those in the energy sector, the provinces and the general public to be heard;

AND WHEREAS under Sub-section 14(2) of the National Energy Board Act "The Board may of its own motion inquire into, hear and determine any matter or thing that under this Act it may inquire into, hear and determine."

IT IS ORDERED THAT:

1. A public inquiry shall be held commencing in the last quarter of 1980 at such times and places in such of the Cities of Vancouver, British Columbia; Calgary, Alberta; Ottawa, Ontario; Quebec City, Quebec; and Halifax, Nova Scotia as the Board shall determine and shall later announce, having regard to the number of persons who have filed written submissions pursuant to the Board's Notice of Public Inquiry, attached hereto, which forms part of this Order.

2. The inquiry will be conducted in either of the official languages and simultaneous interpretation facilities will be provided in locations where it appears from the written submissions filed with the Board that both official languages will be used.

3. The purpose of the inquiry referred to in paragraph 1 is to obtain facts and information by means of viva voce and written evidence, statements of position, and, where necessary, opinions from those persons who have filed written submissions with the Board in response to the Board's Notice of Public Inquiry.

4. The subject matters of the inquiry are set out in detail in a document entitled "Outline for Submissions" which is attached to and forms part of this Order.

5. Any person who wishes to make a submission to the Board on the subject matters of the inquiry shall, unless the Board otherwise orders:

(a) state in his submission in which of the official languages and in which of the cities enumerated in paragraph 1 hereof, he wishes to be heard;

(b) on or before the 5th day of September 1980 file with the Secretary of the Board thirty-five (35) copies of his written submission in either of the official languages;

(c) on or before the 15th day of September 1980 serve a copy of his written submission upon each other person who has filed a written submission with the Board in response to the Board's Notice of Public Inquiry, as determined according to a list to be provided from time to time to all submittors by the Secretary of the Board, and file proof of service with the Board;

(d) avoid the introduction into evidence of any subject beyond the scope of the subject matter of this hearing;

(e) present witnesses to answer questions on his written submission by Board Counsel and by other submittors; and

(f) be entitled to question witnesses or other submittors about their written submissions.

6. Submittors who wish to make a supplemental written submission at the close of the inquiry may do so within one week of the close of the inquiry.

DATED at the City of Ottawa, in the Province of Ontario, this 17th day of April 1980.

NATIONAL ENERGY BOARD

Brian H. Whittle

Secretary

NATIONAL ENERGY BOARD

NOTICE OF PUBLIC INQUIRY

The National Energy Board will hold a public inquiry into the supply of oil, natural gas, and other forms of energy in relation to the domestic demand for all forms of energy, and the supply/demand balances for hydrocarbons and electricity. The inquiry will be held in various cities commencing in the last quarter of 1980. Locations and dates will be announced later.

The inquiry will be conducted in either of the official languages and simultaneous interpretation facilities will be provided in locations where it appears from the written submissions filed with the Board that both official languages will be used.

Interested parties may obtain a copy of the Board's Order No. EHR-1-80 including the Outline for Submissions by writing to the Secretary, National Energy Board, 473 Albert Street, Ottawa, KIA OE5 or by telephoning 613-992-5506.

DATED at Ottawa, Ontario, this 17th day of April, 1980.

NATIONAL ENERGY BOARD

Brian H. Whittle

Secretary

File No.: D1045-3
29 October 1980

MEMORANDUM TO ALL PARTIES

Re: An inquiry into the supply of oil, natural gas, and other forms of energy in relation to the domestic demand for all forms of energy, and the supply/ demand balances for hydrocarbons and electricity — Board Order EHR-1-80

On 22 October 1980 the Board announced a two-week postponement of the start of its energy supply/demand hearing in order to give parties an opportunity to assess the implications of the National Energy Program which was subsequently announced by the Government on 28 October 1980.

The forecasts of energy supply and demand already submitted may be affected by the National Energy Program and the Board wishes to afford submittors an opportunity to amend their forecasts. Should a submittor choose to amend his forecast, he is requested to state clearly the assumptions used and to indicate how they differ from those used in his original forecast.

In addition, the Board wishes to obtain insight into the effect of the National Energy Program on future Canadian energy supply and demand. In this regard, the Board invites submittors to indicate the actions which they perceive as essential in order for the aims of the National Energy Program to be realized. Submittors are requested to comment, in particular, on those actions in which they will be directly involved.

Any submittor who wishes to amend his submission or to coment on the matters set out above is requested to do so in writing by filing 35 copies of his supplementary submission on or before the 30th day of December 1980 with the Secretary of the Board and by serving a copy of his supplementary submission upon each other party to the inquiry.

In the case of submittors who choose to amend or supplement their submissions and who have opted to appear at one of the locations other than Ottawa, the Board invites such parties to provide witnesses and lead evidence on the supplementary filings either in their appearances at the out-of-Ottawa sittings or, should they so wish, at the Ottawa sittings, to commence in January.

Yours truly,

G. Yorke Slader,

Secretary

OUTLINE FOR SUBMISSIONS

GENERAL INSTRUCTIONS

Submittors are encouraged to use, where applicable, the following outline in the preparation of material. Those wishing to provide the Board with estimates of supply or demand are requested to prepare a "base case" representing the levels of supply or demand which, in their opinion, are most realistic.

Questions on this outline should be directed to the following members of the Board staff for the matters indicated:

—supply of oil, natural gas and NGLs, and other forms of energy except electricity (see below for electricity supply)	—K.W. Vollman, Energy Resources Branch, Telephone Number (613) 996-2342
—demand for all forms of energy	—L.B. Harsanyi, Economics Branch, Telephone Number (613) 996-2224
—exports of oil and RPPs	—B.P. Leakey, Oil Policy Branch, Telephone Number (613) 996-2221
—exports of natural gas	—A.L. Browne, Gas Advisory Branch, Telephone Number (613) 996-1906
—exports of LPGs	—B.J. Hodgins, Gas Advisory Branch, Telephone Number (613) 996-2027
—supply and exports of electricity	—T. Olszewski, Electric Power Branch, Telephone Number (613) 996-0383
—economics of supply	—P. Eglington, Economics Branch Telephone Number (613) 996-8776

Note: Short Forms: NGLs — natural gas liquids
RPPs — refined petroleum products
LPGs — liquefied petroleum gases

The Board will welcome submissions on any or all of the subject matters set out in the Order and in this Outline. In that regard, the Board has adopted the following general categories for the submitting of information:

A. Supply

Information on:
(1) reserves and productive capacity of Canadian oil;
(2) reserves and deliverability of Canadian natural gas;
(3) reserves and production of Canadian NGLs;
(4) supply of other forms of Canadian energy; and
(5) the impact of economic factors upon supply.

B. Demand

Information on the demand for:
(1) RPPs;
(2) refinery feedstocks, showing domestic and foreign feedstocks separately;
(3) natural gas;
(4) LPGs;
(5) electricity;
(6) coal and coke; and
(7) other energy forms.

C. Supply/Demand Balances

Information on the estimated supply/demand balances for hydrocarbons and electricity resulting from comparing the supply in A. above with the demand in B. above and, in addition, taking account of expected imports and authorized exports.

All submissions should be expressed in SI units only, expressing all information in units of volume or weight, and energy units (joules), except as otherwise noted.

A. SUPPLY

The Board recognizes that uncertainties regarding geological, technological and economic factors can affect forecasts of supply, and that submittors may choose to submit a range of estimates because of these uncertainties. In such cases, the underlying assumptions for each forecast should be clearly stated so that the effect on supply of changing prices, technology, availability of markets, and so on, are readily apparent. However, in each instance, the submittor is asked to include a forecast which he perceives as the expected case.

Those submittors with the requisite data base are encouraged to submit their data for oil and gas reservoirs on a pool-by-pool basis and for NGLs on a processing plant basis. Use of the standard reporting forms attached is desirable, although use of alternative formats (such as described in AERCB IL 80-3 and IL 79-25) is acceptable if that is more convenient to the submittor. The Board expects that companies which are operators or major participants in a pool or plant will submit data for it. A suggested list of pools and plants in which the Board has a particular interest is attached.

(1) Reserves and Productive Capacity of Canadian Oil

Forecasts with respect to oil supply should include estimates of remaining established reserves and of the average annual ability to produce Canadian crude oil and equivalent, unrestricted by demand, by province or territory for the period 1980 — 2000 for each of the following categories:
(a) conventional crude oil in non-frontier areas from,
(i) established reserves at 1 January 1980,
(ii) appreciation of established reserves, including secondary recovery but excluding tertiary recovery,

(iii) new discoveries, and
(iv) tertiary recovery;

(b) pentanes plus in non-frontier areas from,
(i) established reserves at 1 January 1980, and
(ii) reserves additions;

(c) non-conventional oil recoverable from,
(i) oil sands mining,
(ii) oil sands in situ operations, and
(iii) coal liquefaction; and

(d) crude oil and equivalent from frontier areas.

As in the case of its September 1978 oil report, the Board intends to publish separate supply determinations for light and heavy crude oils. Accordingly, submittors are encouraged to prepare separate forecasts for light and heavy crude oil using the pool definitions given in Appendix 1.

With respect to Category (a)(i) above, the Board suggests that a pool-by-pool forecasting technique be used by those submittors who have access to the requisite data base. The Board expects that companies which are operators or major participants in any of the pools listed in Appendix I will submit a productive capacity forecast for these pools. While this list is intended to serve as a guideline, submittors may wish to provide data on alternative or additional pools where they feel these would improve the accuracy of the overall forecast.

The Board requests that all pool data be submitted in the format illustrated in Appendix 2. Submittors are encouraged to submit any additional data, such as decline curve analyses, economic limits, reservoir model studies and graphic performance analyses which they feel are pertinent to the matter of determining supply. Pages 2 and 3 of Appendix 2 provide guidance for completing the Appendix 2 form. The Board is particularly interested in receiving evidence regarding the potential for improving recovery from established reservoirs (Section D of Appendix 2). Submittors should clearly identify the criteria that would have to be satisfied before the improved recovery technique would be implemented.

With respect to categories (a)(ii) and (iii), submittors are encouraged to detail reserves additions by recovery mechanism and geological horizon with perhaps some additional consideration to ranges of reasonable estimates, and division by geological province. It would be helpful if the major potentially productive horizons within each of the geological systems were identified. Assumptions regarding price, technology and lead times should be clearly stated.

For those submittors providing pentanes plus data on an individual plant basis, additional instructions can be found in Section A. (3), Reserves and Production of Canadian NGLs.

(2) Reserves and Deliverability of Canadian Natural Gas

Submissions with respect to natural gas supply should include estimates of reserves and deliverability by province and territory (or by transmission system) for the period 1980 — 2000 for each of the following categories:

(a) conventional natural gas in non-frontier areas from,
(i) established marketable reserves at 1 January 1980,
(ii) appreciation of established reserves, and
(iii) new discoveries;

(b) non-conventional natural gas from,
(i) very low permeability (tight) reservoirs, and
(ii) synthetic or substitute natural gas made from petroleum liquids or coal; and

(c) natural gas from frontier areas.

With respect to Category (a)(i), submittors are encouraged to submit estimates of reserves and deliverability using the two forms in Appendix 3. Submittors are also invited to provide any additional data such as geological maps, decline curve analyses and reservoir model studies which they feel are pertinent. The Board requests producing companies to submit estimates of reserves and deliverability for pools which they operate, or in which they have a major interest. The Board recognizes, however, that there will be practicable limits to the quantity of data a submittor might be expected to provide, and suggests therefore that companies focus on the following pools in preparing their submissions:

—pools selected by the Board, as listed in Appendix 3;
—pools where the operator's estimate of reserves differs substantially from those published by regulatory agencies; and
—pools where it is felt the Board may lack current information, such as those under active development.

Transmission companies and other gas purchasers with the requisite data base are asked to provide data for pools where they have, or expect to have, purchase contracts, together with summaries of reserves and deliverability from their respective supply areas and by province and territory.

With respect to categories (a)(ii) and (iii), and (b) and (c), it would be helpful if information were provided by geological province and by producing horizon. Submittors may choose to submit a range of forecasts to indicate uncertainty regarding geology, technology and economics. In each instance, the submittor should clearly state the assumptions used and the forecast which he perceives as the most realistic.

(3) Reserves and Production of Canadian NGLs

Submissions with respect to NGL supply should include estimates of reserves (where applicable) and production of ethane, propane, butanes, and pentanes plus for the period 1980 — 2000 for the following categories:

(a) field plants processing gas from established oil and gas reservoirs;
(b) reprocessing plants;
(c) reserves addition;
(d) synthetic crude oil plants;
(e) refineries; and
(f) frontier areas.

With respect to Category (a), the Board suggests that submittors who have access to the requisite data base use a forecasting technique based on an aggregation of production from individual gas processing plants. Submittors who do not have this data base, but who operate, or have a major interest in, a natural gas processing plant which produces or is expected to

produce NGLs, are requested to contribute to this forecast by submitting relevant data on NGL production by component from such plants. A list of the plants which the Board intends to review in detail is attached as Appendix 4. This list is intended as a guide only and submittors may wish to provide data on plants not included in the list. In order to facilitate analysis of the forecasts, the Board requests that all data be submitted in the format shown in Appendix 5. Supporting evidence, such as product yields as a function of reservoir pressure, anticipated production rates and product yields of cycling plants, can be attached to the data sheet. Operators of plants producing an NGL mix should provide a forecast by component based on the expected composition of the mix.

Submittors are encouraged to submit estimates of established reserves for each of the individual NGL components. The Board intends to arrive at its estimate of established reserves by adding the total supply of all individual processing plants by component to its estimate of reserves from unconnected gas reserves. NGL production from reprocessing plants, crude oil refineries and synthetic crude oil plants will not be treated as reserves, but the Board intends to estimate the total supply that will become available from these sources during the forecast period. Submittors using an approach different from the Board's should state clearly the underlying assumptions and list the relevant parameters.

With respect to Category (c), submittors are requested to state clearly their assumptions regarding annual reserves additions of NGLs, annual production rates from reserves additions and yields of individual NGL components.

Category (d) is included to obtain information respecting volumes of propane or other NGLs that could become available through development of the oil sands. Submittors are requested to specify the basic assumptions underlying the forecast.

Supply estimates with respect to Category (e) should exclude volumes used in refineries as fuel or for blending with other refinery products. Forecasts should be based on anticipated refinery runs and submittors are encouraged to provide totals by province or geographic area.

(4) Supply of Other Forms of Canadian Energy

Forecasts and other information should be submitted on the expected contribution to energy supply of other forms of energy such as coal, nuclear and hydroelectric power, wood and wood products, pulping liquor, alcohol, biomass, solar, wind and tidal. In the calculation of total primary energy, hydro and nuclear electricity should be converted to primary energy on a fossil fuel equivalent energy basis, by using the conversion factor of 10.5 megajoules per kwh (10 000 Btu's per kwh).

(5) The Impact of Economic Factors Upon Supply

In addition to the forecasts of supply which are described under parts (1) to (4) above, the Board invites interested parties to provide submissions and studies related to the impact of economic factors such as costs of production, market prices and producer netbacks upon the future Canadian supply of oil and gas. These submissions may be separate or in conjunction with material provided in response to parts (l) to (4) above, but they should deal with impact and supply response at the aggregate industry level. In the context of these submissions, the Board is also interested in estimates of the costs of oil and gas supply additions from conventional and non-conventional sources.

B. DEMAND

As the Board intends to publish an estimate of demand for all forms of energy in Canada, submittors are encouraged to provide estimates of demand in that context, if possible. Submittors are requested to provide a breakdown of Canadian energy demand by energy type including renewable energy for the various sectors in the format outlined in the attached Appendix 7, "Pro Forma Matrix of Total Energy Demand by Sector and Energy Form" for each year 1979 to 1985 and for the years 1990, 1995 and 2000. However, the Board recognizes that many submittors may prefer to submit a forecast for only a part of the total energy spectrum for selected energy forms, for a specific market area, or for a specific market type — and the Board will welcome all such specialized forecasts.

Submittors are requested to provide forecasts of domestic demand for all forms of energy in the detail shown below:

(a) residential;
(b) commercial;
(c) petrochemicals, including fuel and feedstock for basic petrochemicals, such as ammonia, methanol, ethylene and benzene and fuel for their primary derivatives;
(d) other industrial uses, excluding thermal generation of electricity;
(e) transportation, showing air, road, rail and marine separately;
(f) other non-energy use (e.g. lubes, asphalt, etc.);
(g) total sector demand, which is the sum of sectors (a) through (f);
(h) own use and losses, including transmission, processing and distribution losses, and including refinery fuels and pipeline fuel;
(i) thermal generation of electricity, by utilities and by industry; and
(j) total primary energy, which is the sum of points (g), (h) and (i) plus hydro and nuclear electricity converted at 10.5 megajoules per kwh (10 000 Btu's per kwh), less the total amount of electricity generated, including own use and losses.

Geographic Areas (except as otherwise noted)

Atlantic
Quebec
Ontario
Manitoba
Saskatchewan
Alberta
British Columbia
Yukon and Northwest Territories
Total Canada

So that the forecasts can be compared, submittors are requested to specify the assumptions they have made with respect to such matters as economic growth, population growth, relative prices of various types of energy, market shares, expansion of forms of energy into new market areas and any other assumptions which have a bearing on the forecast. It is requested that these assumptions be stated for 1980, 1985, 1990, 1995 and 2000 and that average annual growth rate assumptions be given for each five-year period.

The Board requests that submittors use the following categories in developing their estimates of demand for all forms of energy:

(1) RPPs

Submittors are requested to differentiate RPPs into the following products:

(a)	motor gasoline;	)
(b)	light fuel oil, kerosene and stove oil	) as described in the instruction sheets
		) of the Statistics Canada monthly
(c)	diesel fuel oi;	) report, "Refined Petroleum Products".
(d)	heavy fuel oil;	)
(e)	petrochemical feed-stock;	— those products directly intended for petrochemical processing that are manufactured in oil refining operations (including gases and petrochemical naphtha) but excluding refinery- produced LPGs not directly consumed by associated petrochemical operations.
(f)	aviation gasoline;	
(g)	jet fuel — A;	
(h)	jet fuel — B;	
(i)	asphalt;	
(k)	lubes and greases;	
(k)	other products (excluding LPGs); and	
(l)	total products (excluding LPGs).	

The estimate of demand for RPPs should be provided in both cubic metres and joules.

(2) Refinery Feedstocks, Domestic and Foreign

Submittors are requested to provide a reconciliation between the estimate of total market sales of RPPs and the demand for refinery feedstocks shown in Appendix 6. This material need only be furnished for the base case estimates of demand for RPPs.

The forecasts of total market sales of RPPs should be adjusted for industry use and loss, exports and imports. Regional forecasts should also account for product transfers. The contribution of gas plant butanes to oil product supply should also be segregated, together with the proportion, where applicable, of foreign origin oil in total refinery runs.

Information on the sales of RPPs and the demand for refinery feedstocks is needed for the following years: — actual for 1979, and estimates for each year 1980 to 1985, and for the years 1990, 1995 and 2000.

Information should be shown for Quebec and East, Ontario and West, and for total Canada.

Demand for refinery feedstocks should be shown separately for the following types:

(a) light crude oil and equivalent (including conventional light and medium crude oil, segregated pentanes plus, synthetic crude oil and exchange crude oil imports);
(b) heavy crude oil (including Lloydminster Blend, Wainwright, Viking-Kinsella, Chauvin, Fosterton, Bow River, Smiley Coleville, Midale Weyburn and other streams less than 25¾ API); and
(c) foreign crude oil.

Any significant assumptions or methodology relevant to estimates of the demand for heavy crude oil should be specified including, inter alia, the timing and location of the installation of any anticipated upgrading facilities, the relationship between heavy crude oil production and the estimated demand for asphalt, and generally the ability of existing refineries to process available quantities of heavy crude oil. All forecasts of demand for refinery feedstocks should be expressed in thousands of cubic metres per day to one decimal place and should be accompanied by actual data for one year or more.

(3) Natural Gas

All forecasts of demand for natural gas should be expressed in joules and should be accompanied by actual data for one year or more.

Submittors are requested to provide forecasts of the Canadian demand for marketable natural gas for each calendar year for the years 1980 to 2000 inclusive on the basis of a continuation of the current 85 percent relationship between the city-gate price of natural gas and the refinery-gate price of crude oil at the Toronto reference point. For market areas not currently served by natural gas, eg: Eastern Quebec and the Maritime Provinces, submittors should state their assumptions concerning relative prices of natural gas and other fuels.

(4) LPGs

Submittors are requested to provide estimates of annual demand for LPGs by geographic area for the years 1980 to 2000 for the following products:

(1) ethane;
(2) propane; and
(3) butanes

Forecasts should be expressed in cubic metres and joules and should include both gas plant and refinery LPGs. Volumes blended into other products should, however, be excluded. Submittors are requested to indicate the extent to which markets for LPGs could be expanded. It should be noted that in Appendix 6, LPGs produced in refineries should be added to Total Market Product Sales.

(5) Electricity

Submittors are requested to provide forecasts of demand for electricity by sector, expressed in joules. The forecast should include demand for electricity generated both by utilities and by industries (3 600 000 joules per kwh).

(6) Coal and Coke

Submittors are requested to provide a forecast of demand for coal, by sector, expressed in joules. The coal demand should include coal used to produce coke and coke oven gas.

(7) Other Energy Forms

Submittors are encouraged to provide estimates of energy demand that may be satisfied during the forecast period by such energy forms as wood and wood products, pulping liquor, biomass, solar, wind and tidal. To facilitate the Board's use of such forecasts, submittors are requested to submit estimates in joules, accompanied by the conversion factor used (eg: 1 tonne of wood equates to ...joules).

C. SUPPLY/DEMAND BALANCES

Submittors are encouraged to provide estimated supply/demand balances for hydrocarbons or for electricity, for which they have prepared forecasts of supply and demand.

In estimating the levels of supply of hydrocarbons and electricity within these supply/demand balances, submittors are to take expected imports into account.

In estimating the levels of demand for hydrocarbons and electricity, submittors are to take account of authorized exports.

APPENDIX 1

LIST OF POOLS AND POOL GROUPINGS FOR CRUDE OIL RESERVES AND PRODUCTIVE CAPACITY DATA

Light Crude Oil

Northwest Territories

FIELD	POOL	UNIT
NORMAN WELLS		
Norman Wells	Kee Scarp	—

British Columbia

FIELD	POOL	UNIT
BLUEBERRY TAYLOR PIPELINES		
Aitken Creek	Gething	—
Blueberry	Debolt	—
Eagle	Belloy (85%)	—
Inga	Inga	—
Stoddart West	Total	—
Other	—	—
TRANS-PRAIRIE PIPELINES LTD. BEATTON RIVER—TAYLOR		
Beatton River	Halfway	—
Beatton River West	Bluesky Gething	—
Eagle	Belloy (15%)	—
Milligan Creek	Halfway	—
Peejay	Halfway	—
Weasel	Halfway	—
Wildmint	Halfway	—
Other	—	—
TRANS-PRAIRIE PIPELINES LTD. BOUNDARY LAKE—TAYLOR		
Boundary Lake	Boundary Lake	#1
Boundary Lake	Boundary Lake	#2
Other	—	—
TRUCKED OIL		
Trucked Oil	Total	—

Alberta

FIELD	POOL	UNIT
BOW RIVER PIPELINES LTD. LIGHT & MEDIUM		
Provost	Viking CAK	—
Other	—	—
CREMONA PIPELINE		
Crossfield	Cardium A	—
Harmattan East	Rundle	—
Harmattan Elkton	Rundle C	—
Other	—	—
FEDERATED PIPELINE LTD. ALBERTA		
Carson Creek North	BHL A	—
Carson Creek North	BHL B	—
Judy Creek	BHL A	—
Judy Creek	BHL B	—
Meekwap	D-2A	—
Swan Hills	BHL A&B	—

FIELD	POOL	UNIT
Swan Hills	BHL C	—
Swan Hills South	BHL A&B	—
Virginia Hills	BHL	—
Other	—	—
Gibson Petroleum Co. Ltd.		
Bellshill Lake	Blairmore	—
Thompson Lake	Blairmore	—
Gulf Alberta Pipeline		
Clive	D-2A	—
Clive	D-3A	—
Drumheller	D-2B	—
Duhamel	D-2A	—
Duhamel	D-3B	—
Erskine	D-3	—
Fenn Big Valley	D-2A	—
Hussar	Glauconitic A	—
Joffre	D-2	—
Stettler	D-2A	—
Stettler	D-3A	—
West Drumheller	D-2A	—
Other	—	—
The Imperial Pipe Line Company: Ellerslie		
Acheson	D-3A	—
Golden Spike	D-3A	—
St. Albert Big Lake	D-3A	—
Other	—	—
The Imperial Pipe Line Company Limited: Excelsior		
Excelsior	D-2	—
Fairydell-Bon Accord	D-3A	—
Other	—	—
The Imperial Pipeline Company Limited: Leduc		
Leduc Woodbend	D-2A	—
Leduc Woodbend	D-3A	—
Leduc Woodbend	D-3F	—
Other	—	—
The Imperial Pipe Line Company Limited: Redwater		
Redwater	D-3	—
Murphy Milk River Pipeline		
Coutts	Total	—
Manyberries	Total	—
Other	—	—
Norcen Energy Resources Ltd.		
Joarcam	Viking	—
Peace River Oil Pipe Line Co. Ltd.		
Ante Creek	BHL	—
Cherhill	Banff A	—
Goose River	BHL	—
Kaybob	BHL A	—
Kaybob South	Triassic A	—
Nipisi	Gilwood A (39%)	—
Red Earth	Granite Wash A	—
Simonette	D-3	—
Snipe Lake	BHL	—
Sturgeon Lake	D-3	—
Sturgeon Lake South	D-3	—
Utikuma	KR Sandstone A (16%)	—
Other	—	—
Pembina Pipe Line Ltd.		
Bigoray	Nisku B	—
Brazeau River	Nisku A	—
Pembina	Cardium	—
Pembina	Keystone BR B	—
Pembina	Nisku D	—
Willesden Green	Cardium A (70%)	—
Nisku Other	—	—
Other	—	—
Rainbow Pipeline Company Limited		
Mitsue	Gilwood A	—
Nipisi	Gilwood A (61%)	—
Rainbow	KR A	—
Rainbow	KR B	—
IS No. 1	Other	—
Rainbow	KR F	—
Rainbow	KR I	—
Rainbow	KR AA	—
IS No. 11	Other	—
IS No. 2	Total	—
Rainbow	Other	—
Rainbow South	KR A	—
Rainbow South	KR B	—
Rainbow South	KR E	—
Utikuma	KR Sandstone A (84%)	—
Virgo	Total	—
Zama	Total	—
Other	—	—
Rangeland Pipeline Co. Ltd.		
Ferrier	Cardium D	—
Ferrier	Cardium E	—
Gilby	Jurassic B	—
Gilby	Mannville B	—
Gilby	Viking A	—
Innisfail	D-3	—
Medicine River	Glauconitic A	—
Medicine River	Jurassic A	—
Medicine River	Jurassic C	—
Medicine River	Jurassic D	—
Ricinus	Cardium A	—
Sundre	Rundle A	—
Sylvan Lake	Pekisko B	—
Willesden Green	Cardium A (30%)	—
Other	—	—
Texaco Exploration Canada Ltd.		
Bonnie Glen	D-3A	—
Glen Park	D-3A	—
Westerose	D-3	—
Wizard Lake	D-3A	—
Other	—	—

FIELD	POOL	UNIT
TRANS-PRAIRIE PIPELINES LTD.: BOUNDARY LAKE SOUTH		
Boundary Lake South	Triassic C	—
Boundary Lake South	Triassic E	—
Other	—	—
TWINING PIPELINE DIVISION		
Twining	Rundle A & LM A	—
Twining North	Rundle	—
Other	—	—
VALLEY PIPELINE		
Turner Valley	Rundle & Shallow	—
TRUCK AND TANK CAR		
Truck and Tank Car	Total	—

Saskatchewan

FIELD	POOL	UNIT
WESTSPUR MEDIUM PIPELINE—BATCHED LIGHT		
Flat Lake	Ratcliffe	Vol. Unit #1
Freda Lake	Ratcliffe	—
Neptune	Ratcliffe	—
Sherwood	Frobisher	—
Skinner Lake	Ratcliffe	—
WESTSPUR PIPE LINE COMPANY—S.E. SASKATCHEWAN LIGHT		
Alida East	—	Alida Unit
Carnduff	Midale	East Unit
Elmore	Frobisher Alida	Vol. Unit
Ingoldsby	Frobisher Alida	Vol. Unit
Kenosee	Tilston	Vol. Unit
Parkman	Tilston Souris Valley	—
Queensdale East	Frobisher Alida	Non-Unit
Rosebank	Frobisher Alida	Vol. Unit #1
Steelman	Midale	Unit 1A
Steelman	Midale	Unit II
Steelman	Midale	Unit III
Steelman	Midale	Unit IV
Steelman	Midale	Unit VI
Willmar	Frobisher Alida	Non-Unit
Workman	Frobisher	Vol. Unit #1
Other	—	—

Manitoba

FIELD	POOL	UNIT
TRANS-PRAIRIE PIPELINES LTD.		
Daly	Mississippian	—
North Virden Scallion	Mississippian	—
Routledge	Mississippian	—
Virden Roselea	Mississippian	—
Other	—	—

Ontario

FIELD	POOL	UNIT
ONTARIO		
Ontario	Total	—

LIST OF POOLS AND POOL GROUPINGS FOR CRUDE OIL RESERVES AND PRODUCTIVE CAPACITY DATA

Heavy Crude Oil

Alberta

FIELD	POOL	UNIT
BOW RIVER PIPELINES LTD.: HEAVY		
Bantry	Mannville A	—
Bantry	Mannville D	—
Countess	Upper Mannville B	—
Countess	Upper Mannville D	—
Countess	Upper Mannville H	—
Countess	Upper Mannville O	—
Grand Forks	Upper Mannville B	—
Grand Forks	Lower Mannville D	—
Grand Forks	Lower Mannville K	—
Hays	Lower Mannville A	—
Lathom	Upper Mannville A	—
Taber	Mannville D	—
Taber South	Mannville A	—
Taber South	Mannville B	—
Other	—	—
BP EXPLORATION CANADA LIMITED		
Chauvin	Mannville A	—
Chauvin South	Sparky A & B	—
Chauvin South	Sparky E	—
Chauvin South	Sparky H	—
Chauvin South	Lloydminster D	—
David	Lloydminster A	—
Hayter	Sparky A	—
Other	—	—
HUSKY PIPELINE LTD. & MANITO PIPELINES LTD.		
Lloydminster	Sparky C & GP A	—
Lloydminster	Sparky & GP C	—

FIELD	POOL	UNIT
Viking Kinsella	Wainwright B	—
Wainwright	Wainwright & Sparky A	—
Wildmere	Lloydminster A & Sparky B	—
Other	—	—
Truck and Tank Car (Heavy)		
Cessford	Total	—
Other	—	—

Saskatchewan

FIELD	POOL	UNIT
Husky Pipeline Ltd. & Manito Pipelines Ltd.		
Aberfeldy	Sparky	Aberfeldy Unit
South Aberfeldy	Sparky	Voluntary Unit
Dulwich	Sparky	—
Epping	Sparky & G.P.	Non-Unit
South Epping	Sparky & G.P.	Unit #1
S.W. Epping	Sparky	Vol. Unit #1
Furness	Sparky	—
Golden Lake North	Waseca & Sparky	Vol. Unit
Golden Lake North	Waseca & Sparky	Non-Unit
Golden Lake South	Sparky	—
Golden Lake South	Waseca	—
Gully Lake	Waseca	Vol. Unit #1
Gully Lake	Waseca	Non-Unit
Lashburn	Waseca	Vol. Unit
Lone Rock	Sparky	—
Tangleflags	Total	—
Other	—	—
Bow River Pipe Lines Ltd.		
Coleville	Bakken	—
Dodsland	Viking	Eagle L. Vol. Unit
Dodsland	Viking	Gleneath Unit
Dodsland	Viking Sand	Non-Unit
Eureka	Viking	South Unit
North Hoosier	Bakken	Vol. Unit
North Hoosier	Basal Blairmore	Vol. Unit
Smiley Dewar	Viking	—
Other	—	—
North Hoosier	Basal Blairmore	Vol. Unit
Smiley Dewar	Viking	—
Other	—	—
South Saskatchewan Pipe Line Company		
Battrum	Roseray	Unit #1
Cantuar Main	Cantuar	Unit
Cantuar	Lower Roseray	Unit
Delta	Upper Shaunavon	Unit No. 1
Dollard	Upper Shaunavon	Unit
Fosterton	Roseray	Main Unit
Gull Lake North	Upper Shaunavon	Unit
Instow	Upper Shaunavon	Unit
Main Success	Roseray	Unit
North Premier	Roseray	Unit #3
Rapdan	Upper Shaunavon	Unit
South Success	Roseray	Unit
Suffield	Upper Shaunavon	Unit #2
Suffield	Roseray Sand	Unit #3
Verlo	Roseray	Unit
Other	—	—
Westspur Pipe Line Company		
Benson	Midale	Unit
Innes	Frobisher	—
Lost Horse Hill	Frobisher Alida	Vol. Unit #1
Midale	Central Midale	Unit
Midale	Central Midale	Non-Unit
Oungre	Ratcliffe	Vol. Unit #1
Viewfield	Frobisher	—
Weyburn	Midale	Unit
Weyburn	Midale	Non-Unit
Other	—	—

APPENDIX 2

CRUDE OIL RESERVES AND PRODUCTIVE CAPACITY DATA SHEET

A.
SUBMITTOR:
DATE:

FIELD:
POOL:
UNIT:

B. PRODUCTIVE CAPACITY FORECAST

m³ per day

YEAR	From Established Reserves at 1980-01-01	From Reserves Additions in Section D
1979 (production)		
1980		
1981		
1982		
1983		
1984		
1985		
1986		
1987		
1988		
1989		
1990		
1991		
1992		
1993		
1994		
1995		
1996		
1997		
1998		
1999		
2000		

C. OIL RESERVOIR DATA
For Established Reserves
at 1980-01-01

Area, ha	
Average pay, m	
Rock Volume, $10^4 m^3$	
Porosity, %	
Connate Water, %	
Shrinkage, %	
Initial oil in place, $10^6 m^3$	
Hor. permeability, mD	
Vert. permeability, mD	
Pressure-Datum, m SS	
Initial Pressure, kPa	
Initial oil viscosity, mPa.s	
Current pressure, kPa	
Current oil viscosity, mPa.s	
Primary Recovery, %	
Improved Recovery, %	
Improved Recovery Mechanism	
Total Recoverable Oil, $10^6 m^3$	
Cumulative oil production to 1980-01-01, $10^6 m^3$	
Remaining Established Reserves at 1980-01-01, $10^6 m^3$	

D. POTENTIAL RESERVES ADDITIONS

Check	Improved Recovery Mechanism	# of New Wells	Incremental Recovery $10^6 m^3$	Comments:
☐	Infill Drilling			
☐	Waterflooding			
☐	CO_2			
☐	Hydrocarbon			
☐	Chemical Flooding			
☐	Thermal Techniques			
☐	Other:			
☐	No Potential			

Section A

Normally, productive reservoirs will be identified by completing the spaces marked "FIELD" and "POOL". The space "UNIT" will be left blank except for:

—cases listed in Appendix 1 where a unit, voluntary unit, or non-unit grouping of wells is to be studied; and

—cases in which the submittor may wish to provide a single productive capacity forecast for a pool, but may wish to provide reservoir data (e.g.—recovery factors) on a unit basis. In these cases the submittor would use as many forms as required for the reservoir data, with only the first form in the series containing a pool productive capacity forecast.

Section B

The productive capacity forecast is divided into two columns. The first column should be based on the established reserves provided in Section C, and the second column should be based on the information provided in Section D. Productive capacity is defined as the estimated average annual ability to produce, unrestricted by demand but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing capacity and provincial rate limitations.

Section D

Information provided in Section D will assist the Board in assessing the potential for reserves additions from existing pools through drilling and expanded or new recovery mechanisms. Submittors are requested to indicate the most likely recovery mechanism or, in instances where more than one technique is judged to be potentially applicable, mechanisms can be ranked in order of preference. Comments should include a concise discussion of the salient factors which would influence the choice of technique. Where an operator has not provided a forecast of production from reserves additions in Section B, comments should include a probable starting date for the project and expected incremental production rates from the pool. The category, "No Potential" should be checked only for those cases where costs would be beyond all reasonable expectations, or where suitable technology is unlikely to be developed during the forecast period.

APPENDIX 3

NATURAL GAS DELIVERABILITY DATA SHEET

A.

PLANTS & CAPACITIES:
SUBMITTOR:
DATE OF ESTIMATE:

FIELD:
POOL:
LOCATION:
PRODUCING ZONE:

RESERVES TYPE: —NON ASSOC ☐ GAS CAP ☐ SOLN ☐

B. CAPABILITY FORECAST (from established marketable reserves at 1980-01-01 of ______ 10^6m^3)

Year	$10^3m^3/d$ (as is GHV)	Added: # Wells	Added: Comp'n kW
1979 (production)			
1980			
1981			
1982			
1983			
1984			
1985			
1986			
1987			
1988			
1989			
1990			
1991			
1992			
1993			
1994			
1995			
1996			
1997			
1998			
1999			
2000			

GHV of marketable gas, MJ/m^3 ______

C. RESERVOIR DATA

Mean formation depth (KB)______
Initial reservoir pressure______kPa
Reservoir temperature______°C______K
Drive mechanism______

D. RAW GAS PROPERTIES

Relative Density______
P_c______kPa, T_c______K
Composition (mol percent) C_1______
C_2______C_3______iC_4______nC_4______
iC_5______nC_5______C_6______C_7+______
H_2______He______N_2______
CO_2______H_2S______

E. BASIC DELIVERABILITY DATA

Number of producing wells______
Number of capable wells______
Estimated wells at full development______
Delivery pressure, kPa______
Installed compression, kW______
Estimated producing rate at abandonment______10^3m^3/well/day

CONTRACT DATA

Buyer(s)______
Volume(s) dedicated 10^6m^3______
DCQ(s), $10^3m^3/d$______
Min. day(s), % of DCQ______
Max. day(s), % of DCQ______
Rate(s) of Take______

Well Location	Tubing I.D. mm	Datum Depth	AOF Potential (Raw Gas) Date	AOF 10^3m^3	AOF "n"	AOF BHSIP	Wellhead Deliverability (Raw Gas) Date	WD 10^3m^3	WD "n"	WHSIP	WHFP

Section A

In cases where reserves and deliverability apply to only part of a pool, a plat clearly indicating the part concerned should accompany the form.

Section B

All volumes submitted in Section B should be in respect of *marketable* natural gas. The Board defines supply capability as the deliverability, unconstrained by market demand, that could be achieved when restricted only by reservoir performance, well capability, field processing capacity, expected maximum wells and compression, the existing or assumed contract rate, and provincial rate limitations. Submittors are asked to identify such restrictions to facilitate the Board's understanding of the capability forecast, (i.e.—cycling scheme rates, allowables, facility limitations, etc.).

The gross heating value should be reported on a dry basis.

Section E

The purpose of Section E is to document the basic data used to develop the forecast shown in Section B. Where individual well AOF (Absolute Open Flow) data are not available or were not used, submittors are asked to supply the alternative flow test data actually used, such as a pool average AOF, typical well AOF, or drill stem tests, showing the source (if based on another pool) and any assumptions or procedures employed in deriving average values.

All volumes and rates should be clearly identified as to whether raw or marketable.

NATURAL GAS RESERVES DATA SHEET

FIELD AND POOL__________
SUBMITTED BY__________ DATE__________
TYPE OF RESERVE__________
(ASSOCIATED OR NON-ASSOCIATED)

MEAN FORMATION DEPTH K.B.__________ S.S.__________

TYPE WELL (LOCATION)
__________ W._____M.
TOP OF PAY K.B._____S.S.__________
BASE OF PAY K.B._____S.S.__________

AVERAGE POROSITY (FRACTION)__________
SOURCE__________
CUTOFFS: POROSITY_____SOURCE__________

PERMEABILITY_____SOURCE__________

GAS SATURATION (FRACTION)__________
SW_____SOURCE__________

SO_____SOURCE__________

INITIAL RESERVOIR PRESSURE (kpa)__________
SOURCE__________
RESERVOIR TEMPERATURE_____°C_____K
SOURCE__________

COMPRESSIBILITY FACTOR Z
(Pr_____Tr_____)
SOURCE__________

GAS ANALYSIS Pc_____kPa Tc_____K
RELATIVE DENSITY__________
SOURCE__________

GROSS HEATING VALUE (MJ/m³)__________
SOURCE__________

RESERVE ESTIMATE—INITIAL CONDITIONS	PROVEN	PROBABLE
G/W, metres SS		
G/O, metres SS		
O/W, metres SS		
AREA, hectares		
h, metres		
VOLUME, $10^4 m^3$		
Ø		
GAS SAT., fraction		
P_i, kPa		
T, K		
Z		
m^3/m^3		
GIP, $10^6 m^3$		
RESERVOIR LOSS		
PRODUCIBLE, $10^6 m^3$		
SURFACE LOSS		
MARKETABLE		

MARKETABLE GAS PRODUCED	
REMAINING ESTABLISHED MARKETABLE	
EFFECTIVE DATE	

POOL RECOVERY FACTOR_____% SOURCE__________

SURFACE LOSS FACTOR_____% SOURCE__________

H_2S_____% CO_2_____% C_3+_____% PLANT AND LEASE FUEL_____%
ADDITIONAL COMMENTS__________

LIST OF POOLS AND POOL GROUPINGS FOR MARKETABLE NATURAL GAS RESERVES AND DELIVERABILITY DATA

Alberta

FIELD	POOL
Aden	Rundle A
Atlee Buffalo	Viking B
Basing	Turner Valley
Bellis	Nisku A
Belloy	Notikewin A
Belloy	Debolt A
Belloy	Debolt C
Benjamin	Rundle A
Benjamin	Rundle B
Bindloss	Viking B
Birch	Camrose B
Blueridge	Jurassic B
Burnt Timber	Wabamun A
Calling Lake	D-2B
Carson Creek	Beaverhill Lake A
Carson Creek	Beaverhill Lake B
Cessford	Viking D & H
Cessford	Basal Colorado E
Cessford	Mannville C
Cessford	Mannville H
Chinchaga	Slave Point A
Coleman	Rundle A
Coleman	Palliser A
Coleman	Palliser B
Connorsville	Viking A
Craigend	Grosmont A
Cranberry	Slave Point A
Crimson	D-3A
Crossfield	Rundle A
Crossfield	Basal Quartz A
Crossfield East	Wabamun A
Crossfield East	Elkton A
Donalda	Viking A, C & D
Eaglesham	Debolt A
Edson	Gething A
Enchant	Basal Colorado A
Esther	Banff A
Fairydell-BonAccord	Basal Mannville A
Ferrier	Cardium D
Ferrier	Cardium E
Ferrybank	Lower Mannville A & B
Figure Lake	D-2B
Fir	Triassic A
Fir	Gething A
Fir	D-3A
Fox Creek	Viking A
Fox Creek	Cadomin
Gilby	Basal Mannville H, L, Jurassic-Rundle & Upper Mannville A
Gilby	Basal Mannville D
Gilby	Basal Mannville A & Jurassic D
Gladys	Crossfield 20-27
Gold Creek	Cadomin B

Alberta (Cont'd)

FIELD	POOL
Gold Creek	Bluesky-Gething A
Gold Creek	Wabamun A
Granor	Grosmont A
Greencourt	Jurassic A
Greencourt	Pekisko A
Hanlan	Swan Hills 47-17
Heart River	Notikewin
Holmberg	Glauconitic A
Hunter Valley	Rundle A
Hussar	Viking B
Hussar	Ostracod F
Hussar	Ostracod R
Hussar	Basal Mannville B
Jarrow	Glauconitic I
Jumping Pound West	Rundle A & B
Kaybob	Notikewin A
Kaybob	Notikewin B
Kaybob South	Cadomin A
Kaybob South	Cadomin B
Kaybob South	Cadomin C
Kaybob South	Cadomin D
Kaybob South	Beaverhill Lake A
Kirby	Upper Mannville A
Kirby	Clearwater C 74-05
Liege	Grosmont
Limestone	Rundle A
Limestone	Rundle B
Limestone	Wabamun 32-09
Limestone	Wabamun 33-10
Limestone	Leduc 36-32-10
Limestone	Leduc 14-33-10
Lone Pine Creek	Wabamum A
Lone Pine Creek	D-3A
Lookout Butte	Rundle A
Lovett River	Rundle A
Medicine Lodge	Viking A
Medicine River	Pekisko P
Minehead	Beaverhill Lake 49-19
Mountain	Triassic
Nevis	Devonian
Okotoks	Crossfield
Olds	Wabamun A
Olds	Wabamun C
Oyen	Viking A & Detrital B
Paddle River	Jurassic-Detrital-Rundle
Pembina	Lobstick Glauconitic A
Pembina	Lobstick Glauconitic C & D
Pine Creek	Wabamun
Pine Creek	Wabamun C
Pine Creek	D-3
Pine North West	D-3A
Pouce Coupe	Peace River A
Provost	Mannville Z

ALBERTA (CONT'D)

FIELD	POOL
Retlaw	Mannville B & D
Richdale	Viking A & C
Rowley	Pekisko A
Salter	Mount Head 26-08
Salter	Turner Valley 26-08
Savanna Creek	Rundle A
Shaw	Rundle
Sinclair	Doig
Standard	Viking A
Stanmore	Viking A & B
Sylvan Lake	Elkton-Shunda B
Virginia Hills	Belloy A
Waterton	Rundle C
Waterton	Rundle D & E
Waterton	Rundle A & H
Waterton	Rundle-Wabamun A
Waterton	Wabamun B
Whitecourt	Pekisko E

BRITISH COLUMBIA

FIELD	POOL
Buick Creek	Dunlevy A
Buick Creek	Dunlevy B
Buick Creek	Dunlevy C
Bullmoose	Baldonnel A
Cabin	Slave Point A
Cabin	Slave Point B
Cabin	Slave Point C
Clarke Lake	Slave Point A
Grizzly North	Halfway A
Grizzly North	Halfway B
Grizzly South	Dunlevy A
Helmet	Slave Point A
Kotcho Lake	Slave Point A
Kotcho Lake	Slave Point C
Kotcho Lake East	Slave Point C
Louise	Slave Point
Oak	Halfway A
Petitot River	Slave Point
Sierra	Elk Point A
Sierra	Elk Point B
Silver	Bluesky A
Sukunka	Baldonnel A
Sukunka	Baldonnel B
Sukunka	Baldonnel C
Velma	Gething
Yoyo	Elk Point A

NORTHWEST TERRITORIES

FIELD	POOL
Pointed Mountain	Nahanni

APPENDIX 4

LIST OF GAS PROCESSING AND REPROCESSING PLANTS FOR NGL SUPPLY FORECAST

GAS PLANT	LOCATION	OPERATOR
Acheson	2-53-26W4	Canadian Propane Gas and Oil of Alberta Ltd.
Ante Creek	18-65-23W5	Amoco Canada Petroleum Company Ltd.
Bigoray	10-7-51-9W5	Chevron Standard Limited
Blueberry Mountain	11-16-82-7W6	DeKalb Petroleum Corporation
Bonnie Glen	SW17-47-27-W4	Texaco Canada Resources Ltd.
Boundary Lake South	SE14-85-13W6	Esso Resources Canada Limited
Brazeau River	6-10-44-12W5	CDC Oil & Gas Limited
Brazeau River	12-46-14W5	Hudson's Bay Oil and Gas Company Limited
Brazeau River	SW31-48-12W5	Petro-Canada Exploration Inc.
Burnt Timber	10-13-30-7W5	Shell Canada Resources Limited
Canadian Industries—Edmonton		Canadian Industries Limited
Caroline	12-36-34-6W5	Altana Exploration Company
Caroline	SW20-34-4W5	Hudson's Bay Oil and Gas Company Limited
Carson Creek	4-23-61-12W5	Mobil Oil Canada, Ltd.
Carstairs	6-3-30-2W5	Home Oil Company Limited
Cessford	2-8-24-12W4	Hudson's Bay Oil and Gas Company Limited
Cherhill	4-24-56-5W5	Dome Petroleum Limited
Chip Lake	10-29-53-10W5	Lario Oil & Gas Company
Cochrane	16-26-4W5	Alberta Natural Gas Company Ltd.
Connorsville	9-32-25-15W4	Petro-Canada Exploration Inc.
Cranberry	1-24-96-5W6	Dome Petroleum Limited
Crossfield	1-2-26-29W4	Petrogas Processing Ltd.
Crossfield East	9-14-28-1W5	Amoco Canada Petroleum Company Ltd.

GAS PLANT	LOCATION	OPERATOR
Duhamel	3-32-45-21W4	Mobil Oil Canada, Ltd.
Dunvegan	15-3-81-4W6	Anderson Exploration Ltd.
Edmonton Ethane Plant	4-52-24W4	Dome/Canadian Utilities Limited
Edson	3&4-11-53-18W5	Hudson's Bay Oil and Gas Company Limited
Elmworth	SE8-70-11W6	Canadian Hunter Exploration Ltd.
Elmworth	4-8-69-8W6	Sulpetro of Canada Ltd.
Empress	12-20-1W4	Dome Petroleum Limited
Empress	11-20-1W4	Petro-Canada Exploration Inc.
Ferrier	2-6-41-7W5	Amerada Minerals Corporation of Canada Ltd.
Ferrier	14/15-21-38-7W5	Esso Resources Canada Limited
Ferrier	1-20-39-7W5	Texas Pacific Oil Canada Ltd.
Ferrybank	2-1-44-28W4	PanCanadian Petroleum Limited
Fort Saskatchewan	14-55-22W4	Chevron Standard Limited
Garrington	2-20-34-3W5	Amerada Minerals Corporation of Canada Limited
Garrington	13-5-34-3W5	DeKalb Petroleum Corporation
Garrington	11-17-34-3W5	Dome Petroleum Limited
Ghost Pine	8-11-31-21W4	Gulf Canada Resources Inc.
Ghost Pine	4-33-31-23W4	Mobil Oil Canada, Ltd.
Gilby	10-10-41-3W5	Canadian Homestead Oils Limited
Gilby	1-24-41-3W5	Chevron Standard Limited
Gilby	6-13-40-3W5	Gulf Canada Resources Inc.
Gilby	5-5-40-3W5	Petro-Canada Exploration Inc.
Gilby	15-22-40-3W5	Texaco Canada Resources Ltd.
Gold Creek	NW27-67-5W6	Petro-Canada Exploration Inc.
Golden Spike	NW22-51-27W4	Esso Resources Canada Limited
Greencourt	9-26-59-9W5	Petrofina Canada Ltd.
Harmattan East	NE27-31-4W5	Canadian Superior Oil Ltd.
Homeglen Rimbey	S5-44-1W5	Gulf Canada Resources Inc.
Hussar	13-36-24-21W4	C D C Oil and Gas Limited
Innisfail	1-3-35-1W5	Shell Canada Resources Limited
Joffre	14-36-38-27W4	Chevron Standard Limited
Joffre	15-17-39-26W4	Esso Resources Canada Limited
Josephine	NE1-83-10W6	Amoco Canada Petroleum Company Ltd.
Judy Creek	15-25-64-11W5	Esso Resources Canada Limited
Jumping Pound	13-13-25-5W5	Shell Canada Resources Limited
Kaybob	8-9-64-19W5	Petro-Canada Exploration Inc.
Kaybob South	15-59-18W5	Chevron Standard Limited
Keybob South	1&12-62-20W5	Hudson's Bay Oil and Gas Company Limited
Leduc-Woodbend	2-34-50-26W4	Esso Resources Canada Limited
Lone Pine Creek	6-27-29-28W4	Canadian Superior Oil Ltd.
Lone Pine Creek	6-23-30-28W4	Hudson's Bay Oil and Gas Company Limited
Medicine River	6-16-38-4W5	Dome Petroleum Limited
Minnehik-Buck Lake	10-5-46-6W5	Candel Oil Limited

GAS PLANT	LOCATION	OPERATOR
Mitsue	30-72-4W5	Chevron Standard Limited
Nevis	15-22-39-22W4	Chevron Standard Limited
Nevis	9-33-38-22W4	Gulf Canada Resources Inc.
Nipisi	30-72-4W5	Amoco Canada Petroleum Company Ltd.
Niton	16-55-13W5	Altana Exploration Company
Niton	10-56-11-W5	Dome Petroleum Limited
Niton	14-18-54-12W5	Esso Resources Canada Limited
Niton	7-34-54-14W5	Norcen Energy Resources Limited
Olds	6-18-32-1W5	Amerada Minerals Corporation of Canada Ltd.
Paddle River	13-6-57-8W5	Canada-Cities Services Limited
Pembina	13-24-48-7W5	Amoco Canada Petroleum Company Ltd.
Pembina	5-35-48-4W5	Canada-Cities Services Ltd.
Pembina	15-48-3W5	Dome Petroleum Limited
Pembina	13-22-49-10W5	Texaco Canada Resources Ltd.
Pembina	NE36-47-4W5	Western Decalta Petroleum Limited
Penhold	10-30-36-27W4	Ceja Corporation
Pincher Creek	23-4-29W4	Gulf Canada Resources Inc.
Provost	9-19-36-5W4	Dome Petroleum Limited
Quirk Creek	4-21-4W5	Esso Resources Canada Limited
Rainbow	10-10-109-8W6	Aquitalne Company of Canada Ltd.
Rainbow	12-23-110-7W6	Esso Resources Canada Limited
Rainbow	10-110-6W6	Mobil Oil Canada, Limited
Redwater	29-57-21W4	Esso Resources Canada Limited
Ricinus	6-31-33-7W5	Amerada Minerals Corporation of Canada Limited
Ricinus	11-30-35-8W5	Amoco Canada Petroleum Company Ltd.
Rockyford	10-24-26-23W4	Western Decalta Petroleum Limited
Rosevear	NE11-54-15W5	Shell Canada Resources Limited
Rosevear	33-54-15W5	Suncor Inc.
Simonette	6-63-25W5	Shell Canada Resources Limited
Strachan	6-2-37-10W5	Aquitaine Company of Canada Limited
Strachan	11-35-37-9W5	Gulf Canada Resources Inc.
Sturgeon Lake South	2-69-22W5	Hudson's Bay Oil and Gas Company Limited
Sundance	6-25-54-21W5	Hudson's Bay Oil and Gas Company Limited
Swan Hills	1-8-70-10W5	Shell Canada Resources Limited
Sylvan Lake	1-21-38-2W5	Chevron Standard Limited
Sylvan Lake	13-25-37-3W5	General American Oils, Limited
Sylvan Lake	14-32-37-3W5	Hudson's Bay Oil and Gas Company Limited
Tony Creek	1-4-62-21W5	Dome Petroleum Limited

GAS PLANT	LOCATION	OPERATOR
Turner Valley	14-6-20-2W5	Western Decalta Petroleum Limited
Twining North	SW31-32-24W4	Hudson's Bay Oil and Gas Company Limited
Virginia Hills	10-17-64-13W5	Shell Canada Resources Limited
Vulcan	SE24-15-22W4	Dome Petroleum Limited
Waterton	20-4-30W4	Shell Canada Resources Limited
Wayne Rosedale	12-4-28-20W4	C D C Oil & Gas Company Limited
Wayne Rosedale	1-20-28-21W4	PanCanadian Petroleum Limited
Westlock	26-54-25W4	Norcen Energy Resources Limited
Whitecourt	12-26-59-11W5	Petro-Canada Exploration Inc.
Whitelaw		Dome Petroleum Limited
Wildcat Hills	6-16-26-5W5	Petrofina Canada Ltd.
Willesden Green	13-16-40-5W5	Canadian Homestead Oils Limited
Willesden Green	1-17-42-6W5	Texaco Canada Resources Ltd.
Wilson Creek	1-29-43-4W5	Amerada Minerals Corporation of Canada Limited
Wimborne	4-12-34-26W4	Mobil Oil Canada, Ltd.
Windfall	8-17-60-15W5	Amoco Canada Petroleum Company Ltd.
Worsley	7-22-87-7W6	Shell Canada Resources Limited
Zama	NW12-116-6W6	Hudson's Bay Oil and Gas Company Limited
Steelman	21-4-5W2	Steelman Gas Limited
Taylor		Westcoast Transmission Company Ltd.

APPENDIX 5

NATURAL GAS LIQUIDS DATA SHEET

A. SUBMITTOR: PLANT:
DATE:

B. Supply
From Established Reserves
At 1980-01-01

Year	C_2 m³/d	C_3 m³/d	C_4 m³/d	C_5+ m³/d
1979 (production)				
1980				
1981				
1982				
1983				
1984				
1985				
1986				
1987				
1988				
1989				
1990				
1991				
1992				
1993				
1994				
1995				
1996				
1997				
1998				
1999				
2000				

C. GAS: Source & Composition
Gas Pools Dedicated to Plant

Pool	Gas Purchaser

1979
Average Gas Composition
(Mol percent)

Component	Plant Inlet Gas	Plant Sales Gas
Methane		
Ethane		
Propane		
i- Butane		
n- Butane		
Pentanes+		
Nitrogen		
H_2S		
CO_2		
Other		

D. Plant and Related Facilities

Actual Plant Capacity________ $10^6 m^3/d$
Minimum Plant Throughput________ $10^6 m^3/d$
If liquids are transported from the plant by pipeline, identify component and system________
If NGL mix is shipped/received for processing, identify destination/source of the mix________
Planned Modifications________

APPENDIX 6

DEMAND FOR REFINERY FEEDSTOCKS (CRUDE OIL & EQUIVALENT)

$(10^3 m^3/d)$

	1979	1980	1981	1982	1983	1984	1985	1990	1995	2000
QUEBEC AND EAST										
Total Domestic Sales of Refined Petroleum Product										
Add Sales of Refinery Produced LPGs.										
Deduct Product Imports										
Add Product Exports										
Net Product Transfers Out/(In)										
Losses, Industry Use and Other Adjustments										
Deduct Gas Plant Butanes Supplied to Refineries										
Total Feedstocks Demand										
—Domestic										
—Foreign										
ONTARIO AND WEST										
Total Domestic Sales of Refined Petroleum Product										
Add Sales of Refinery Produced LPGs										
Deduct Product Imports										
Add Product Exports										
Net Product Transfers Out/(In)										
Losses, Industry Use and Other Adjustments										
Deduct Gas Plant Butanes Supplied to Refineries										
Total Feedstocks Demand										
—Domestic										
—Foreign										
CANADA										
Total Domestic Sales of Refined Petroleum Product										
Add Sales of Refinery Produced LPGs										
Deduct Product Imports										
Add Product Exports										
Losses, Industry Use and Other Adjustments										
Deduct Gas Plant Butanes Supplied to Refineries										
Total Feedstocks Demand										
—Domestic										
—Foreign										

APPENDIX 6A

BREAKDOWN OF REFINERY DEMAND FOR DOMESTIC FEEDSTOCKS

	1979	1980	1981	1982	1983	1984	1985	1990	1995	2000
QUEBEC AND EAST										
Domestic Light and Equivalent										
Domestic Heavy										
Total										
ONTARIO AND WEST										
Domestic Light and Equivalent										
Domestic Heavy										
Total										
CANADA TOTAL										
Domestic Light and Equivalent										
Domestic Heavy										
Total										

PRO FORMA MATRIX OF TOTAL DOMESTIC ENERGY DEMAND BY SECTOR AND ENERGY
(Unit: 10^{15} joules)

		Coal, Coke & Coke Oven Gas	Ethane	Propane	Butanes[i]	Oil Products	Natural Gas	Elec-tricity	Hog Fuel & Pulp Liq.	Other Renewable Energy	Hydro[ii]	Nuclear[ii]	Total Energy
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Residential	x		x	x	x	x	x		x			x
2	Commercial			x	x	x	x	x		x			x
3	Petrochemical		x	x	x	x	x						x
4	Other Industrial	x[iii]		x	x	x	x	x	x	x			x
5	Transportation —Road					x							x
6	—Rail	x				x							x
7	—Air					x							x
8	—Marine					x							x
9	Total Transportation	x				x							x
10	Other Non Energy Use					x							x
11	TOTAL SECTOR DEMAND	x	x	x	x	x	x	x	x	x			x
12	Own Use & Losses	x	x	x	x	x	x	x					x
13	Electricity Generation	x				x	x		x	x	x	x	x
14	TOTAL	x	x	x	x	x	x	x	x	x	x	x	x
15	Minus Total Electricity												—
	(col. g, row 14)												
16	TOTAL PRIMARY ENERGY	x	x	x	x	x	x		x	x	x	x	x

Notes:
(i) Excludes butanes blended in gasoline.
(ii) Assuming 10 546 150 joules for each Kwh of electricity generated (or 10,000 Btu s per Kwh.)
Includes coal losses in the production of coke and coke oven gas.

PRO FORMA MATRIX OF TOTAL DOMESTIC PETROLEUM PRODUCTS DEMAND BY SECTOR AND PRODUCT
(Unit: 10^{15} joules)

		AVGAS	MOGAS	AVJET-A	AVJET-B	LFO & Kerosene	Diesel	H.F.O.	Asphalt	Lubes & Greases	Petrochem. Feedstock	Other Products	Total Oil Products
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Residential					x	x	x					x
2	Commercial					x	x	x					x
3	Petrochemical										x		x
4	Other Industrial					x	x	x					x
5	Transportation —Road		x				x						x
6	—Rail						x						x
7	—Air	x		x	x								x
8	—Marine						x	x					x
9	Total Transportation	x	x	x	x		x	x					x
10	Other Non Energy Use								x	x		x	x
11	TOTAL SECTOR DEMAND	x	x	x	x	x	x	x	x	x	x	x	x
12	Own Use & Losses	x	x	x	x	x	x	x	x	x	x	x	x
13	Electricity Generation						x	x					x
14	TOTAL PRIMARY ENERGY	x	x	x	x	x	x	x	x	x	x	x	x

Notes: Column (1) "Total Oil Products" to be carried over to page 1, Column (e).

DEMOGRAPHIC AND ECONOMIC GROWTH

The Board's macroeconomic forecasts were prepared using a version of the CANDIDE econometric model.

Base Case Macroeconomic Forecast

The Board's base case macroeconomic forecast is summarized in Tables C-l and C-2.

For the 1980s, the Board's forecast is that growth in real Gross National Expenditure (GNE) averages 3.1 percent per·year while inflation, as measured by the Consumer Price Index (CPI), increases at an average rate of 8.1 percent per year spurred by higher domestic energy prices. This modest economic performance prevents the unemployment rate from declining substantially throughout the decade, and it averages 7.2 percent. In the 1990s real economic growth accelerates somewhat to an annual average rate of 3.4 percent. This, combined with slower labour force growth, causes the unemployment rate to decline, averaging 6.1 percent over the decade.

The forecast incorporates a fertility rate which remains constant at the replacement level of 2.1 children per female of child-bearing age throughout the forecast horizon. Net immigration attains levels of 40 000 and 60 000 persons in 1981 and 1982 respectively. Thereafter, net immigration is kept constant at 80 000 persons per year. These factors produce an annual rate of growth in population which declines gradually over the forecast period, from an average annual rate of 1.1 percent during the 1980s to an average rate of 0.9 percent per year during the 1990s. By the year 2000 the resultant population is 29 million persons, which is within the range of Statistics Canada's most recent population projections.

Increased participation of women in the labour force contributes to the aggregate labour force participation rate which increases steadily throughout the forecast period, from a level of about 64 percent in 1980 to a level of 71 percent by the year 2000.

With the exception of the housing industry, the investment sector provides the bright spot of this forecast, both in the medium and longer term. Led by fixed private non-residential investment, particularly in energy-related projects during the 1980s, the investment sector is the main engine of real growth in the next two decades (see Table C-1). Investment as a share of GNE increases steadily throughout the forecast horizon, with most of the increase taking place in the 1980s.

The trade sector continues to play a major role in Canada's growth performance throughout the forecast period. The combination of a devalued Canadian dollar with better relative cost performance vis-à-vis Canada's major trading partners provides strength to real export growth.

In the 1980s growth in real consumer expenditure is forecast to average only 2.4 percent per year as a result of the negative effects of persistently high rates of inflation and unemployment on real incomes. Although growth in real consumer outlays accelerates somewhat during the 1990s it remains below the overall growth in real GNE.

Table C-1

COMPONENTS OF REAL[1] GROSS NATIONAL EXPENDITURE
Range of NEB Forecasts
Average Annual Growth Rates
(percent per year)

	Actual			Forecast	
	1961-1970	1971-1980		1981-1990	1991-2000
Gross National Expenditure	5.2	3.9	Base	3.1	3.4
			High	3.9	4.0
Business Investment in Plant and Equipment	5.2	5.8	Base	4.7	4.9
			High	5.6	5.4
Residential Construction	3.5	3.0	Base	1.3	1.2
			High	1.6	1.4
Consumer Expenditure	4.4	4.7	Base	2.6	3.0
			High	3.7	3.5
Government Current Expenditure	6.7	2.5	Base	1.6	2.5
			High	2.1	3.1
Exports	9.3	4.2	Base	3.9	4.1
			High	4.3	4.7
Imports	7.1	5.5	Base	3.4	3.9
			High	4.1	4.2

[1] Measured in constant dollars.

Table C-2

PROJECTIONS OF THE CANADIAN ECONOMY
Range of NEB Forecasts
Average Annual Growth Rates
(percent per year)

	Actual			Forecast	
	1961-1970	1971-1980		1981-1990	1991-2000
Real Gross National Expenditure	5.2	3.9	Base	3.1	3.4
			High	3.9	4.0
Population	1.8	1.1	Base	1.1	0.9
			High	1.1	1.0
Employment	2.7	3.0	Base	1.7	1.7
			High	1.9	1.8
Households	2.8	2.9	Base	2.2	1.3
			High	2.3	1.4
Consumer Price Index	2.7	8.0	Base	8.1	6.5
			High	7.6	6.0
Real Personal Disposable Income	4.7	5.4	Base	2.5	3.0
			High	3.5	3.5
RDP Commercial Sector	5.3	4.4	Base	3.1	3.5
			High	3.9	4.1
RDP Industrial Sector	5.6	3.6	Base	3.8	3.8
			High	4.7	4.6
Productivity	2.5	1.1	Base	1.5	1.8
			High	2.1	2.4
Unemployment Rate(1)(%)	4.7	6.9	Base	7.2	6.1
			High	7.0	5.6
Real Per Capita GNP(2) (1980 dollars per Person)	9 225	12 069	Base	14 685	18 740
			High	15 839	21 250

(1) Average level over period, rather than growth rate.
(2) Level at end of period, rather than growth rate.

It is assumed that government spending restraint, particularly federal, will continue throughout the forecast period. This leads to weak growth in real government expenditures.

Residential construction activity remains weak during most of the forecast period. Declining population growth discussed above combined with relatively strong growth in the housing stock during the 1970s, leave very little room for a strong expansion in this sector during the remainder of the century. Housing starts average 189 000 units per year over the forecast period and growth in the total stock of houses exceeds growth in demand with the result that the vacancy rate remains at recent levels. Rising home heating costs strengthen the tendency towards building more multiple than single dwellings over the forecast period. As a result of this, the stock of single houses as a percentage of the total housing stock declines from 56 percent in 1979 to about 53 percent by the year 2000.

Productivity is predicted to increase at a slower rate than during the 1960s and in the early part of the 1970s. Rising domestic energy prices and shifts in the composition of output from high to low-productivity industries are the main factors that contribute to the modest average productivity gain of 1.6 percent per year over the forecast horizon.

Inflation, as measured by the CPI, is projected to stay in the 10 to 12 percent range in 1981-82 and average 8.1 percent per year during the 1980s. Rising domestic energy prices and slow growth in productivity account for most of the inflationary pressures present over the 1980s. Beyond 1990, increases in the CPI abate somewhat as the adjustment of the economy to higher domestic energy prices is completed.

High Case Macroeconomic Forecast

To assess the impact upon energy demand of changing economic conditions the Board has also prepared a more optimistic high case forecast of the Canadian economy. While the base case forecast is predicated upon most likely estimates for the exogenous variables, the high case forecast is based on values which are possible, though less likely than the values used in the base case, and which are conducive to stronger economic growth. These two forecasts are compared in Tables C-1 and C-2 and were used to underpin the energy demand cases. The

energy demand cases and their relationship to the macroeconomic forecasts and energy price assumptions are discussed in section 5.3.

The changes made for the high macroeconomic case fall into two broad categories: those that increase the economy's potential for growth and those that increase aggregate demand.

The high case includes 20 000 more net immigrants in each year of the forecast period than does the base case. The resultant total population of 29.5 million persons in the year 2000 is one half million greater than in the base case forecast. Also, in the high case the average rate of growth in labour productivity is projected to increase by 2.2 percent per year compared with an average rate of 1.6 percent in the base case. Both of these assumptions increase the economy's potential for growth.

On the demand side of the economy, the economic outlook for the United States and overseas economies is much stronger than the one assumed in the base case. This provides considerable stimulus to Canadian exports which in turn leads to stronger aggregate demand. Real government current expenditures also grow at a faster rate than in the base case and this results in stronger domestic demand. Housing starts average 198 000 units per year throughout the forecast period, compared with 189 000 units per year in the base case, resulting in stronger real growth in residential construction expenditures. Despite the increased level of housing starts, the vacancy rate remains about the same as in the base case as the stronger growth in the housing stock is offset by the increased growth in household formation stemming from a faster growing population.

As a result of these changes, the high case macroeconomic forecast is characterized by faster growth of population and real GNE. Real GNP per capita is higher by 13.4 percent in the year 2000 than in the base case. Although the level of unemployment in both cases is approximately the same by the year 2000, it falls more rapidly from current levels in the high case. Inflation, as measured by the CPI, increases less rapidly than in the base case, particularly after 1985.

THE MACROECONOMIC IMPACT RESULTING FROM POSTPONEMENT OR CANCELLATION OF OIL SANDS PROJECTS AND FROM OTHER OIL PRODUCTION CUTBACKS

INTRODUCTION

A number of Submittors expressed concern about the macroeconomic impacts of delays or cancellation of oil sands projects and cutbacks in other oil production. To estimate the overall economic consequences of delays or cancellation, the Board, developed two energy scenarios for illustrative purposes only. Both of these scenarios are highly improbable, but illustrate the range of effects possible.

The first scenario examines the effects of a temporary reduction in conventional oil production from 1981 to 1985 and delays of five years in the expansion of existing oil sands plants and in the construction of new projects. The reduction in conventional oil production corresponds to that announced by the Government of Alberta: 9.5 thousand cubic metres (60,000 barrels) per day on each of 1 March, 1 June and 1 September, 1981. For the purpose of this appendix, the reserves not produced in earlier years, as a result of the reduction in conventional oil production, are not assumed to add to productive capacity in later years. Compared with the base case macroeconomic forecast this would reduce conventional oil production by about 7.5 million cubic metres in 1981 and by 10.5 million cubic metres per year over the period 1982 to 1985. Thereafter, conventional oil production would return to the levels projected in the base case macroeconomic forecast. There would be no investment in oil sands plants until 1986. Oil sands plant investments of some $10 billion in 1980 dollars, would be postponed and start in 1986 and thereafter.

In the second scenario, oil sands plant cancellation and permanent oil production cutbacks were assumed in order to illustrate the worst possible outcome. This scenario examines the effects of a permanent reduction in conventional oil production and of no expansion of existing oil sands facilities nor construction of new oil sands projects during the forecast period. Conventional oil production would be cut back by the same annual amounts as in the first scenario over the period 1981 to 1985, by 7.5 million cubic metres in 1981 and by 10.5 million cubic metres per year from 1982 to 1985. After 1985, the cutback of 10.5 million cubic metres would continue until the year 2000. There would be no investment in oil sands plants during the whole forecast period. This would represent a total reduction in investment of some $29.6 billion in 1980 dollars relative to the base case.

In both scenarios the decrease in total domestic oil production is fully ofset by increased oil imports, and the level of the petroleum compensation charge is adjusted correspondingly to cover the additional costs imposed on the oil import compensation program.

It should be noted that a reduction in conventional oil production would affect any associated gas production. Also, the elimination of oil sands projects examined in the second scenario would reduce natural gas demand. These effects on natural gas production and demand were not considered.

RESULTS

Scenario I

Scenario I and base case results are compared in Table D-1. The delay in oil sands investments and the oil production cutbacks for 5 years would moderately reduce overall economic growth and the level of employment of the Canadian economy in the short term. Real GNE in 1985, would be lower by some $5.9 billion in 1980 dollars, or by 1.8 percent, while employment would be lower by about 116 000 persons, or by 1.0 percent, than in the base case forecast. The increase in oil sands investment in the later years would cause some acceleration in real GNE and employment growth and by 2000 both real GNE and employment would be slidhtly higher than in the base case. The impact on domestic inflation would be marginal.

The increased oil imports caused by the temporary cutbacks in conventional oil production and the delays in the construction of oil sands plants would lead to a significant deterioration in the current account balance of some $2.1 billion in 1985 to $7.1 billion in 1990. Slower economic growth in the earlier years of the forecast period would adversely affect the federal government budget balance which would deteriorate by some $5.1 billion in 1985 and $6.5 billion in 1990, all in constant, 1980 dollars.

OIL SANDS INVESTMENT IN SCENARIO I
(millions of 1980$)

	Syncrude Expansion	Cold Lake	Alsands	Petro-Can NOVA	Scenario Unidentified	Base I Total	Case Total
1981-1985	—	—	—	—	—	—	9 860
1986-1990	1 335	5 001	4 557	667	—	11 560	12 227
1991-1995	445	556	1 000	4 890	3 556	10 447	7 113
1996-2000	—	—	—	—	7 113	7 113	445
Total[1]	1 778	5 558	5 558	5 558	10 671	29 121	29 644

[1] Components may not add to totals due to rounding.

Table D-1

MACROECONOMIC IMPACT OF SCENARIO I

	1981-1985	1986-1990	1991-1995	1996-2000
Additional Crude Oil Imports				
(millions of cubic metres)	52	57	75	33
(billions of 1980$)	11.9	12.9	17.1	7.6
Real GNE Growth (average annual growth rate in percent)				
Base Case	3.0	3.1	3.2	3.6
Scenario I	2.6	3.5	3.3	3.6
	1985	1990	1995	2000
Real GNE (billions of 1980$)				
Base Case	334.1	389.3	455.7	544.2
Scenario I	328.2	389.7	459.2	547.4
Difference (percent)	−1.8	0.1	0.8	0.6
Real Investment (billions of 1980$)				
Base Case	84.1	100.6	124.8	154.9
Scenario I	78.9	100.6	125.5	155.1
Difference (percent)	−6.2	0.0	0.6	0.1
Total Employment (thousands)				
Base Case	11 676	12 648	13 737	15 002
Scenario I	11 560	12 640	13 794	15 096
Difference (percent)	−1.0	−0.1	0.4	0.6
Unemployment Rate (level in percent)				
Base Case	6.8	6.7	6.2	5.0
Scenario I	7.6	6.7	5.8	4.4
Difference (level)	0.8	0.0	−0.4	−0.6
Consumer Price Index (1980 = 100)				
Base Case	154.7	217.5	301.5	408.8
Scenario I	155.5	218.3	302.6	410.9
Difference (percent)	0.5	0.3	0.4	0.5
Current Account Balance(1)				
(billions of 1980$)				
Base Case	−4.5	−2.1	0.2	0.9
Scenario I	−6.6	−9.2	−6.1	−5.0
(share of GNE in percent)				
Base Case	−1.3	−0.5	0.4	0.2
Scenario I	−2.0	−2.3	−1.3	−0.9
Federal Government Balance(1)				
(billions of 1980$)				
Base Case	−3.3	1.2	10.9	23.8
Scenario I	−8.4	−5.3	3.7	15.6
(share of GNE in percent)				
Base Case	−1.0	0.3	2.4	4.4
Scenario I	−2.5	−1.3	0.8	2.8

(1) Converted to 1980 dollars using the GNE price deflator.

Scenario II

Scenario II and base case results are compared in Table D-2. The cancellation of oil sands investment and a permanent cutback of conventional oil production have, as expected, a more significant impact.

The lower levels of investment in Scenario II would slow down economic growth so that real GNE would be lower by some $5.9 billion in 1985, or by 1.8 percent, and $6.8 billion, or by 1.7 percent, in 1990. These figures are in 1980 dollars. Employment would also be lower by about 116 000 persons, or by 1.0 percent, and 153 000 persons, or by 1.2 percent in 1985 and 1990 respectively.

The production cutbacks and increased oil imports, in spite of the investment reductions, would have a negative effect on the domestic rate of inflation as a result of the higher petroleum compensation charge imposed to cover the additional costs of imported oil. The CPI would be higher by some 0.5 percent in 1985 and 1.7 percent in 1990 than in the base case.

The increased oil imports would mainly affect Canada's Current Account Balance which is forecast to deteriorate under this scenario by some $2.1 billion in 1985 and $9.7 billion in 1990, in 1980 dollars.

A slower growing economy, on the other hand, would significantly affect the federal government budget balance which, rather than attaining a surplus by the late 1980s as in the base case, would continue to show large deficits throughout almost all of the forecast period.

CONCLUSIONS

Total energy-related investments in the base case macroeconomic forecast represent on average 24.7 percent of total fixed capital formation over the period 1981-1985, and 23.6 percent over the period 1986-1990. Energy-related investments amount to 5.7 percent of GNE over the period 1981-1985, and 5.8 percent over the period 1986-1990. Investments in oil sands facilities, with a participation of about 11 percent in total energy-related investment over the period 1981 to 1990, do not represent more than 2.7 percent of total fixed investments nor more than 0.7 percent of GNE over this period.

Thus, a delay, or even an outright cancellation, of oil sands investments would have a moderate effect on overall growth and employment in the Canadian economy. However, the regional impact affecting several provinces would be considerably more severe given the absolute amount of the delayed or cancelled investments, which would amount to almost $10 billion in 1980 dollars, in the period 1981 to 1985.

Cutbacks in the production of crude oil, temporary or permanent, combined with delays or cancellation of new oil sands developments and the related production of synthetic crude, would produce an important effect on the levels of crude oil imports and related policies or measures, such as the import compensation program and petroleum compensation charges. The impact of delays and cancellation would show up mainly in the balance on Current Account of the Balance of Payments and in the fiscal position of the federal government.

The impact discussed above would be mitigated if additional frontier oil supplies were brought on stream during the forecast period.

Table D-2

MACROECONOMIC IMPACT OF SCENARIO II

	1981-1985	1986-1990	1991-1995	1996-2000
Additional Crude Oil Imports				
(millions of cubic metres)	52	109	184	218
(billions of 1980$)	11.9	24.9	42.1	49.7
Real GNE Growth (average annual growth rate in percent)				
Base Case	3.0	3.1	3.2	3.6
Scenario II	2.6	3.1	3.3	3.7
	1985	1990	1995	2000
Real GNE (billions of 1980$)				
Base Case	334.1	389.3	455.7	544.2
Scenario II	328.2	382.5	450.5	539.6
Difference (percent)	–1.8	–1.7	–1.1	–0.8
Real Investment (billions of 1980$)				
Base Case	84.1	100.6	124.8	154.9
Scenario II	78.9	95.6	120.1	150.7
Difference (percent)	–6.2	–5.0	–3.8	–2.7
Total Employment (thousands)				
Base Case	11 676	12 648	13 737	15 002
Scenario II	11 560	12 495	13 591	14 871
Difference (percent)	–1.0	–1.2	–1.1	–0.9
Unemployment Rate (level in percent)				
Base Case	6.8	6.7	6.2	5.0
Scenario II	7.6	7.7	7.0	5.6
Difference (level)	0.8	1.0	0.8	0.6
Consumer Price Index (1980ę100)				
Base Case	154.7	217.5	301.5	408.8
Scenario II	155.5	221.3	308.8	421.5
Difference (percent)	0.5	1.7	2.4	3.1
Current Account Balance[1]				
(billions of 1980$)				
Base Case	–4.5	–2.1	0.2	0.9
Scenario II	–6.6	–11.8	–16.3	–22.5
(share of GNE in percent)				
Base Case	–1.3	–0.5	0.04	0.2
Scenario II	–2.0	–3.1	–3.6	–4.2
Federal Government Balance[1]				
(billions of 1980$)				
Base Case	–3.3	1.2	10.9	23.8
Scenario II	–8.4	–8.6	–5.3	1.6
(share of GNE in percent)				
Base Case	–1.0	0.3	2.4	4.4
Scenario II	–2.5	–2.2	–1.2	0.3

[1] Converted to 1980 dollars using the GNE price deflator.

OUTLINE OF THE NATIONAL ENERGY PROGRAM

The major provisions of the NEP are presented in the following sections:

(a) New Taxes and Income Tax Changes

Petroleum and Gas Revenue Tax (PGRT)

This new tax applies to gross oil and gas production revenue less operating costs. Deductions such as those for exploration and development expenditures, capital cost allowances, interest or Crown royalties, are not allowed. The tax itself is not deductible for income tax or provincial royalty purposes. The PGRT starts at eight percent for 1981 but is subject to review if oil prices rise faster than $1 per barrel ($6.29/m³) every six months.

Tax on Natural Gas and Liquefied Petroleum Gases (LPG)

This new tax on the sale of natural gas starts at $.28/ gigajoule and increases progressively to a rate of $.70/gigajoule by 1983. On a heating value basis, the same rates apply to LPG.

Depletion Allowance on Development and Exploration Expenditures

Prior to the NEP, enhanced recovery equipment earned a depletion allowance at a rate of 50 percent and oil sands equipment at a rate of 33 1/3 percent. Heavy crude oil upgrading facilities did not qualify for such an allowance. Other exploration and development expenditures earned a depletion allowance of 33 1/3 percent.

The NEP has eliminated the depletion allowance on all conventional oil and gas development expenditures. Qualifying expenditures, net of any incentive payments in oil sands mining, tertiary oil projects and heavy crude upgrading plants will earn a depletion allowance at a rate of 33 1/3 percent. This earned depletion will now be deductible up to a ceiling of 25 percent of resource income instead of the previous limit of 50 percent of total income.

The 33 1/3 percent depletion allowance on domestic exploration expenditures, net of any incentive payments, is maintained for 1981 but phased out for areas outside the Canada Lands by 1984. The depletion allowance for net exploration expenditures on Canada Lands remains at 33 1/3 percent.

Exploration Expense

The NEP and subsequent announcements by the Government indicate that the definition of exploration expenditures which qualify for incentive payments and income tax deductions will change becoming effective in 1982. For conventional areas, the new definition indicates that discovery wells and wells which are abandoned receive exploration expense treatment. In frontier areas, delineation wells, where drilling commenced prior to the start of commercial production, discovery wells, and abandoned wells qualify for exploration expense tax treatment under the Income Tax Act. The former definition currently in effect, allows production wells to qualify for exploration well treatment if the well is not expected to commence commercial production within twelve months of its completion in addition to discovery and abandoned wells.

(b) Energy Prices

Conventional Oil Price

The conventional oil price schedule under the NEP shown in Tables E-1 and E-2 provides wellhead prices which increase $2 per barrel ($12.58/m³) in each of 1981, 1982 and 1983, $4.50 per barrel ($28.31/m³) in 1984 and 1985, and $7 per barrel ($44.03/m³) in each year from 1986 to 1990.

Tertiary Oil Recovery Price

The NEP provides an incentive price for oil produced by tertiary recovery methods. The price starts at $30 per barrel ($188.70/m³) in 1981 and will be adjusted based on the Consumer Price Index in order to converge with the conventional oil price by 1990 as shown in Tables E-1 and E-2.

Oil Sands Price Schedule

The NEP establishes an oil sands reference price of $38 per barrel ($239.02/m³) escalated with the Consumer Price Index as shown in Tables E-1 and E-2. An exception is production from the existing Suncor plant which will receive the conventional oil price while any expanded production will receive the reference price.

Blended Oil Price

The NEP introduced the Petroleum Compensation Charge which when added to the conventional oil price gives the cost of oil to refineries. This charge incorporates the former Syncrude levy and progressively increases in order to pass the cost of oil imports on to consumers. The charge will be $2.55 per barrel ($16.04/m³) for 1981 increasing by $2.50 per barrel ($15.73/m³) in December of 1981, 1982 and 1983 reaching $10.05 per barrel ($63.21/m³) by 1984 as shown in Table E-3.

The government has also established a charge to finance an increase in public ownership in the energy sector. This charge will be added as acquisitions are made.

The blended price will never exceed 85 percent of the international price or the average price of oil in the United States, whichever is lower.

Natural Gas Prices

The NEP establishes an Eastern Canada refinery-gate price for natural gas which will be set at the same level in Toronto, Montreal, Québec City and Halifax. For the three-year period starting 1 November, 1980, the price of gas, including the natural gas tax, in the eastern zone will rise 42 cents per gigajoule (45 cents per Mcf) per year as shown in Tables E-1 and E-2. The Government has also established a charge to finance an increase in public ownership in the energy sector. This charge will be added as acquisitions are made.

Table E-1

NATIONAL ENERGY PROGRAM: WELLHEAD OIL PRICES[1]

Oil Sands[2] Reference Price	Tertiary Recovery Oil[3] (15° API gravity)	Conventional Oil (38° API gravity) ($/bbl)	
Jan. 1980	—	14.75	
Aug. 1980	—	–16.75	
Jan. 1981	38.00	30.00	17.75
July 1981			18.75
Jan. 1982	41.85	33.05	19.75
July 1982			20.75
Jan. 1983	45.80	36.15	21.75
July 1983			22.75
Jan. 1984	49.85	39.35	25.00
July 1984			27.25
Jan. 1985	54.10	42.70	29.50
July 1985			31.75
Jan. 1986	58.55	46.20	35.25
July 1986			38.75
Jan. 1987	63.20	49.90	42.25
July 1987			45.75
Jan. 1988	68.30	53.90	49.25
July 1988			52.75
Jan. 1989	73.75	58.20	56.25
July 1989			59.75
Jan. 1990	79.65	62.85	63.25
July 1990			66.75

(1) Adapted from page 26 of the NEP.
(2) Subject to cap of international price.
(3) In later years, the price for tertiary recovery oil will depend upon the price for conventional oil. As the price for conventional oil approaches that for tertiary recovery, price differentials will develop to reflect quality differences, i.e., the cost of upgrading. The price of tertiary recovery oil will never be less than the price for conventional oil of a similar quality.

NATURAL GAS PRICES AND TAXES[4]

($/Mcf)

	Cumulative Natural Gas Tax	Eastern Canada City-Gate Price	Total
Oct. 31, 1980		2.60	2.60
Nov. 1, 1980	0.30	2.60	2.90
July 1, 1981	0.45	2.60	3.05
Jan. 1, 1982	0.60	2.60	3.20
Feb. 1, 1982	0.60	2.75	3.35
Aug. 1, 1982	0.60	2.90	3.50
Jan. 1, 1983	0.75	2.90	3.65
Feb. 1, 1983	0.75	3.05	3.80
Aug. 1, 1983	0.75	3.20	3.95

(4) Adapted from page 35 of the NEP.
Canadian ownership charge not included.

Table E-2

NATIONAL ENERGY PROGRAM: WELLHEAD OIL PRICES[1]

	Oil Sands[2] Reference Price	Tertiary Recovery Oil[3] (15° API gravity) ($/m³)	Conventional Oil (38° API gravity)
Jan. 1980	—	—	92.78
Aug. 1980	—	—	105.38
Jan. 1981	239.02	188.70	111.65
July 1981			117.94
Jan. 1982	263.24	207.88	124.23
July 1982			130.52
Jan. 1983	288.08	227.38	136.81
July 1983			143.10
Jan. 1984	313.56	247.51	157.25
July 1984			171.40
Jan. 1985	340.29	268.58	185.56
July 1985			199.71
Jan. 1986	368.28	290.60	221.72
July 1986			243.74
Jan. 1987	397.53	313.87	265.75
July 1987			287.77
Jan. 1988	429.61	339.03	309.78
July 1988			331.80
Jan. 1989	463.89	366.08	353.81
July 1989			375.83
Jan. 1990	501.00	395.33	397.84
July 1990			419.86

(1) Adapted from page 26 of the NEP.
(2) Subject to cap of international price.
(3) In later years, the price for tertiary recovery oil will depend upon the price for conventional oil. As the price for conventional oil approaches that for tertiary recovery, price differentials will develop to reflect quality differences, i.e., the cost of upgrading. The price of tertiary recovery oil will never be less than the price for conventional oil of a similar quality.

NATURAL GAS PRICES AND TAXES[4]

$/GJ

	Cumulative Natural Gas Tax	Eastern Canada City-Gate Price	Total
Oct. 31, 1980	—	2.47	2.47
Nov. 1, 1980	.28	2.47	2.75
July 1, 1981	.42	2.47	2.89
Jan. 1, 1982	.56	2.47	3.03
Feb. 1, 1982	.56	2.61	3.17
Aug. 1, 1982	.56	2.75	3.31
Jan. 1, 1983	.70	2.75	3.45
Feb. 1, 1983	.70	2.89	3.59
Aug. 1, 1983	.70	3.03	3.73

(4) Adapted from page 35 of the NEP.

Table E-3

ILLUSTRATIVE BLENDED PRICE CALCULATION[1]

	Aug. 1980	Dec. 1980	Dec. 1981	Dec. 1982	Dec. 1983
			($/bbl)		
Conventional Oil Price	16.75	16.75	18.75	20.75	22.75
Petroleum Compensation Charge	1.75	2.55	5.05	7.55	10.05
Blended Price[2]	18.50	19.30	23.80	28.30	32.80
			($/m³)		
Conventional Oil Price	105.36	105.36	117.94	130.52	143.10
Petroleum Compensation Charge	11.01	16.04	31.76	47.49	63.21
Blended Price[2]	116.37	121.40	149.70	178.01	206.31

[1] Based on Page 30, NEP
[2] Transportation costs to particular refining centres and Canadian ownership charge are additional.

(c) Energy Supply Incentive Programs

Petroleum Incentives Program

The NEP introduced the Petroleum Incentives Program which will compensate companies at varying levels, depending on the Canadian Ownership Rating (COR), for qualifying exploration, development and special project expenditures. The incentives vary from 10 to 35 percent of exploration and development expenditures in conventional areas outside the Canada Lands for companies exceeding 50 percent Canadian ownership. In frontier areas (Canada Lands) the incentives for exploration vary from 25 percent to 80 percent depending on the level of Canadian ownership. Development incentives in the frontiers vary from 10 to 20 percent depending on the degree of Canadian ownership of the company.

Natural Gas Bank and Domestic Market Expansion

The NEP will assist the holders of shut-in gas by accelerating the development of domestic markets and by providing a $400 million fund to purchase gas.

Crude Oil Upgrading Incentives

The NEP increases the income tax deductions available to a heavy crude oil upgrading facility and allows the upgraded crude oil to receive a price in excess of the conventional oil price but not greater than the oil sands reference price.

(d) New Legislation — Canada Lands

The NEP introduced new legislation for Canada Lands which contains a number of provisions for frontier and offshore exploration and development which will revise land tenure and drilling requirement regulations. The legislation will also reserve to the Crown a 25 percent interest in every right on Canada Lands. This interest will be in the form of a carried interest, convertible to a working interest at any time prior to the authorization of a production system for a particular field.

The government will require a minimum of 50 percent Canadian ownership for any production from Canada Lands.

A ten percent basic royalty plus a Progressive Incremental Royalty based on the profitability of each producing field will apply.

(e) Oil Substitution Measures

A major objective of the NEP is a rapid shift from oil to other more abundant fuels. In each of the residential, commercial and industrial sectors in every province, the goal is to reduce oil consumption to ten percent of total energy use. In the transportation sector, the goal is to halt and eventually reverse, the growth of oil consumption. A related objective is to improve the efficiency with which Canada uses its crude oil supplies.

Foremost is the policy of pricing natural gas to the consumer relatively cheaper in comparison to oil products. A range of oil substitution measures are presented in the NEP under the heading of "Direct Action Programs", and they include incentives for conversion, pipelines extensions, expansion of energy distribution systems, alternatives to gasoline, increased oil-use efficiency, and increased use of renewable energy. The Atlantic provinces will receive additional funding for other off-oil programs.

Natural Gas Pricing

City-gate prices for natural gas will be set at the same level in Toronto, Montreal, Québec City and Halifax. The ratio of gas prices to oil will thus fall significantly in the next three years. The city-gate price of natural gas as a percent of the blended price of crude oil in Eastern Canada, will decrease from 80 percent in 1980 to 67 percent in 1983.

Conversion Incentives

The NEP states that the federal government will seek agreements with the provinces to implement a program of incentives to assist homeowners and businesses to convert from oil. While details of the program may vary among provinces, the basic program will provide taxable grants to subsidize conversion from oil heating to natural gas, electricity or other services. The grants will cover 50 percent of the conversion cost, up to a grant maximum of $800, for conversions made after 28 October 1980.

No new residential unit built after 1 July, 1981 will qualify for federal financial assistance or guarantees if it is heated by oil unless no reasonable alternative is available.

The federal government will establish a substantial fund to finance the capital cost of fuel-system conversions in building and facilities owned by the federal government and federal Crown agencies.

Pipeline Extensions

The NEP states that the federal government has the objective of having gas available to Maritime consumers by 1983. It will set aside up to $500 million, to be used, if required, to support the extension of natural gas pipelines into the Maritimes and to Vancouver Island.

Expansion of Energy Distribution Systems

To ensure the rapid expansion of gas pipeline distribution systems, market-development bonuses will be offered to distributors upon commitment by the Provincial government to the ten percent oil share target, and agreement that the gas price incentive be used in part to pay for gas pipeline expansion rather than simply passed on to existing gas consumers.

Alternatives to Gasoline

For commercial fleets, taxable grants of up to $400 will be provided for each vehicle converted to propane. The federal government will convert its vehicles to propane wherever practicable, with a target of at least 8 000 propane vehicles over the next five years.

The development of compressed natural gas as a motor fuel will be encouraged through a number of other programs.

Oil-Use Efficiency

The NEP states that the federal government has obtained commitments from four refiners to reduce substantially their output of heavy fuel oil by installing equipment to upgrade it into light products. As a result, the NEP expects that heavy fuel oil production will fall by some 12 000 cubic metres (75 000 barrels) a day by 1985.

The NEP also states that Petro-Canada is studying the possibility of installing a central upgrading plant to process some 13 000 cubic metres (80 000 barrels) a day of heavy fuel oil from all Montreal refineries.

The NEP includes a commitment by the fedeal government to participate financially in a $1 billion heavy crude upgrading plant in Saskatchewan.

Petrochemicals

The NEP states that the petrochemical industry should not plan on using more oil in 1990 than it does now. It is suggested that the industry should depend on natural gas, LPG's or coal as a feedstock for future plants.

Renewable Energy

To further enhance renewable energy supply, the federal government is establishing a new Canadian alternative energy corporation, Enertech Canada, to support the commercial production of renewable energy and conservation technologies.

To encourage greater displacement of petroleum by biomass fuels, the Forest Industries Renewable Energy Program, which provides grants to forest industry firms that convert to wood-waste fuels, will be expanded to apply to other biomass fuels and to cover all industrial and commercial establishments. The existing $4 million limit on grants will be removed.

(f) Energy Conservation Measures

The NEP will expand and strengthen conservation actions in the private and public sectors.

An enhanced conservation program will be offered in provinces and territories where neither natural gas nor reasonably priced electricity is available as an alternative to oil. A maximum of $800 covering 50 percent of eligible costs will be provided. Eligible measures include energy audits, oil furnace retrofits and additional insulation.

Federal funding for the Canadian Home Insulation Program which provides home insulation grants of up to $500, will be increased from $80 million to $265 million annually.

The National Housing Act will be used to support national energy objectives. Any new house, for which federal financing is sought after 1 July 1981, will be required to meet federal energy-efficient standards. The federal government will also develop new energy-efficient standards for houses built in northern Canada and accelerate its program to retrofit federal buildings including 25 000 housing units that it owns at defence bases, weather stations, transport facilities and national parks.

An expanded energy audit program will be instituted to assist industries and businesses to identify and eliminate energy waste. An Industrial Conservation Program unique to the Atlantic provinces will provide up to 50 percent of the cost of energy efficient improvements in the industrial sector.

Mandatory automobile fuel economy standards appropriate for Canadian conditions will be established under new legislation.

Some $20 million has been earmarked for a cooperative program that would combine the two goals of job creation and conservation in Canada's municipalities.

(g) Electricity in the Atlantic Region

An immediate priority of the NEP is to replace existing oil-fired generating capacity in the Atlantic Region by lower-cost alternatives. A utility off-oil fund provides for grants of up to 75 percent of the cost of environmentally acceptable conversions of oil-fired electricity plants to coal, with a ceiling of $175 million for the conversion program.

In addition to oil substitution measures the NEP provides federal support in the Atlantic Region for interprovincial electrical interconnection, hydro development on the lower Churchill in Labrador, research and production in the coal mining industry in Nova Scotia, as well as other energy efficient projects.

PRIMARY ENERGY DEMAND - CANADA - 1980 ESTIMATE

COMPARISON OF FORECASTS

(PETAJOULES)

		NATURAL GAS INCLUDING ETHANE	OIL	LPG	COAL	HOG FUEL AND PULPING LIQUOR	OTHER RENEWABLE ENERGY	ELECTRICITY HYDRO	ELECTRICITY NUCLEAR	TOTAL PRIMARY ENERGY
CPA		1 775	4 105	100	915	315		2 645	365	10 220
GULF	POST-NEP	1 888	4 085	105	856	303	26	2 196	523	9 981
IMPERIAL	PRE-NEP	1 787	4 074	122	994	316	17	2 567	364	10 240
IMPERIAL	POST-NEP	1 787	4 073	122	993	317	16	2 567	364	10 240
NORCEN	POST-NEP	1 685	4 092		980			2 253	328	9 338
NOVA		1 860	4 146							9 700
PETRO-CANADA	(MAR.12,1981)	1 790	3 682	65	870		15	2 301	379	9 105
SHELL	PRE-NEP	1 898	4 133	68	891	201	12	2 382	371	9 956
TEXACO	PRE-NEP	1 966	4 096	119	988	332	8	2 277	331	10 116
NEB	MIDDLE DEMAND CASE	1 820	4 008	89	1 019	318	9	2 660	436	10 358

PRIMARY ENERGY DEMAND - CANADA - 1985

COMPARISON OF FORECASTS

(PETAJOULES)

		NATURAL GAS INCLUDING ETHANE	OIL	LPG	COAL	HOG FUEL AND PULPING LIQUOR	OTHER RENEWABLE ENERGY	ELECTRICITY HYDRO	ELECTRICITY NUCLEAR	TOTAL PRIMARY ENERGY
GULF	POST-NEP	2 443	3 854	184	1 230	347	27	2 664	701	11 449
IMPERIAL	PRE-NEP	2 156	3 956	139	1 151	369	17	2 927	679	11 395
NORCEN	POST-NEP	2 117	3 750		1 143			2 614	585	10 209
NOVA		2 243	3 967							10 715
PETRO-CANADA	(MAR.12,1981)	2 335	3 485	62	1 125		57	2 670	577	10 310
SHELL	PRE-NEP	2 217	4 250	73	979	250	10	2 582	666	11 026
SHELL	POST-NEP	2 390	4 013	73	979	250	10	2 582	666	10 963
TEXACO	PRE-NEP	2 253	3 988	146	1 161	405	43	2 648	591	11 234
NEB	MIDDLE DEMAND CASE	2 424	3 830	103	1 145	381	9	3 044	852	11 788

PRIMARY ENERGY DEMAND - CANADA - 1990

COMPARISON OF FORECASTS

(PETAJOULES)

		NATURAL GAS INCLUDING ETHANE	OIL	LPG	COAL	HOG FUEL AND PULPING LIQUOR	OTHER RENEWABLE ENERGY	ELECTRICITY HYDRO	ELECTRICITY NUCLEAR	TOTAL PRIMARY ENERGY
CPA		2 364	4 334	188	1 396	443	43	3 074	968	12 810
GULF	POST-NEP	2 852	3 820	273	1 494	403	32	3 165	1 088	13 127
IMPERIAL	PRE-NEP	2 503	3 791	170	1 399	443	19	3 185	1 045	12 554
IMPERIAL	POST-NEP	2 503	3 789	170	1 409	442	20	3 185	1 045	12 564
NORCEN	POST-NEP	2 310	3 652		1 284			3 105	760	11 111
NOVA		2 539	3 991							11 889
PETRO-CANADA	(MAR.12,1981)	2 649	3 407	55	1 442		116	3 181	798	11 647
SHELL	PRE-NEP	2 710	4 089	76	1 083	277	20	2 847	749	11 850
SHELL	POST-NEP	3 040	3 749	76	1 083	277	20	2 847	749	11 840
TEXACO	PRE-NEP	2 636	3 955	157	1 329	484	106	3 163	779	12 613
NEB	MIDDLE DEMAND CASE	2 799	3 691	160	1 336	448	88	3 356	982	12 860

PRIMARY ENERGY DEMAND - CANADA - 1995

COMPARISON OF FORECASTS

(PETAJOULES)

	NATURAL GAS INCLUDING ETHANE	OIL	LPG	COAL	HOG FUEL AND PULPING LIQUOR	OTHER RENEWABLE ENERGY	ELECTRICITY HYDRO	ELECTRICITY NUCLEAR	TOTAL PRIMARY ENERGY
GULF POST-NEP	3 225	3 923	218	1 922	472	86	3 702	1 346	14 893
IMPERIAL PRE-NEP	2 779	3 871	189	1 696	527	54	3 310	1 250	13 675
NORCEN POST-NEP	2 524	3 654		1 455			3 566	995	12 194
NOVA	2 895	3 942							13 147
PETRO-CANADA (MAR.12,1981)	3 002	3 453	49	1 729		159	3 761	1 111	13 264
SHELL PRE-NEP	2 946	4 235	79	1 164	292	33	2 949	964	12 660
TEXACO PRE-NEP	3 018	3 876	157	1 534	540	164	3 670	1 029	13 988
NEB MIDDLE DEMAND CASE	3 090	3 835	210	1 711	507	164	3 515	1 058	14 089

PRIMARY ENERGY DEMAND - CANADA - 2000

COMPARISON OF FORECASTS

(PETAJOULES)

	NATURAL GAS INCLUDING ETHANE	OIL	LPG	COAL	HOG FUEL AND PULPING LIQUOR	OTHER RENEWABLE ENERGY	ELECTRICITY HYDRO	ELECTRICITY NUCLEAR	TOTAL PRIMARY ENERGY
GULF POST-NEP	3 496	4 127	153	2 415	570	158	4 217	1 569	16 704
IMPERIAL PRE-NEP	2 978	3 960	211	2 132	580	153	3 550	1 448	15 013
IMPERIAL POST-NEP	2 978	3 960	211	2 129	579	155	3 550	1 448	15 011
NORCEN POST-NEP	2 723	3 810		1 643			4 063	1 286	13 525
NOVA	3 274	4 129							14 782
PETRO-CANADA (MAR.12,1981)	3 336	3 624	48	2 060		195	4 359	1 506	15 128
SHELL PRE-NEP	3 198	4 531	81	1 268	324	57	3 233	999	13 689
SHELL POST-NEP	3 588	3 956	81	1 268	324	57	3 233	999	13 504
TEXACO PRE-NEP	3 466	4 066	152	1 767	613	269	4 228	1 342	15 904
NEB MIDDLE DEMAND CASE	3 546	4 178	223	2 051	568	267	3 927	1 416	16 176

TOTAL ENERGY DEMAND

RESIDENTIAL SECTOR - NEWFOUNDLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEWFOUNDLAND	22.6	22.8	23.0	24.2	25.6
NEB MIDDLE DEMAND CASE	25.1	26.7	27.4	28.7	30.5

TOTAL ENERGY DEMAND

RESIDENTIAL SECTOR - NOVA SCOTIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NOVA SCOTIA POST-NEP	43.3	48.4	52.0	55.6	59.4
NEB MIDDLE DEMAND CASE	46.5	49.0	52.3	54.1	57.9

TOTAL ENERGY DEMAND

RESIDENTIAL SECTOR - NEW BRUNSWICK

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEW BRUNSWICK		42.3			
NBEPC	16.3	20.0	24.4		
NEB MIDDLE DEMAND CASE	34.0	38.5	40.8	43.5	45.7

TOTAL ENERGY DEMAND

RESIDENTIAL SECTOR - PRINCE EDWARD ISLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEB MIDDLE DEMAND CASE	7.0	7.3	7.9	8.7	9.2

TOTAL ENERGY DEMAND

RESIDENTIAL SECTOR - ATLANTIC

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	103.8	88.8	88.6	92.7	96.3
IMPERIAL	PRE-NEP	109.0	106.0	104.0	105.0	107.0
SHELL	POST-NEP	88.6	88.1	85.3		77.7
NEB	MIDDLE DEMAND CASE	112.9	121.6	128.1	134.9	143.1

TOTAL ENERGY DEMAND

RESIDENTIAL SECTOR - QUEBEC

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	281.6	238.8	236.6	234.1	229.5
IMPERIAL	PRE-NEP	345.0	347.0	345.0	340.0	342.0
TCPL	POST-NEP	272.4	281.4	294.0	303.6	314.2
NEB	MIDDLE DEMAND CASE	300.6	294.8	304.6	328.8	356.8

TOTAL ENERGY DEMAND

RESIDENTIAL SECTOR - ONTARIO

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	415.9	406.1	412.6	421.3	430.7
IMPERIAL	PRE-NEP	476.0	469.0	453.0	443.0	460.0
ONTARIO	PRE-NEP	476.0	462.0	458.0	457.0	464.0
ONTARIO	POST-NEP				438.0	
SHELL	POST-NEP	357.8	361.6	351.3		332.4
TCPL	POST-NEP	428.7	461.4	488.5	506.2	524.8
NEB	MIDDLE DEMAND CASE	434.4	432.8	442.3	465.3	485.8

TOTAL ENERGY DEMAND

RESIDENTIAL SECTOR - MANITOBA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	44.6	44.0	44.0	43.8	44.4
MANITOBA POST-NEP	57.3	60.2	62.8	65.0	66.9
SHELL PRE-NEP	41.0	40.4	38.2	36.3	34.5
TCPL POST-NEP	46.2	46.2	47.6	48.6	50.0
NEB MIDDLE DEMAND CASE	54.1	55.7	59.0	62.6	69.7

TOTAL ENERGY DEMAND

RESIDENTIAL SECTOR - SASKATCHEWAN

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	55.2	55.9	56.9	58.4	61.0
SPC	42.3	48.0	51.7	55.4	58.7
SHELL PRE-NEP	49.3	50.6	48.1	46.2	44.2
TCPL POST-NEP	50.8	50.2	50.1	49.5	49.0
NEB MIDDLE DEMAND CASE	74.9	78.8	80.4	83.0	89.2

TOTAL ENERGY DEMAND

RESIDENTIAL SECTOR - ALBERTA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	117.2	128.8	137.8	147.5	158.3
IMPERIAL PRE-NEP	159.0	171.0	186.0	197.0	208.0
SHELL PRE-NEP	125.4	142.3	143.9	145.2	145.6
TCPL VOL.3,HIGH CASE	124.9	143.4	156.5	163.7	169.3
NEB MIDDLE DEMAND CASE	153.9	169.8	172.9	184.1	205.3

TOTAL ENERGY DEMAND

RESIDENTIAL SECTOR - BRITISH COLUMBIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
B.C.		145.5	161.9	176.8	
IMPERIAL PRE-NEP	133.0	137.0	139.0	144.0	148.0
TCPL POST-NEP	102.1	109.7	118.4	125.0	132.6

TOTAL ENERGY DEMAND

RESIDENTIAL SECTOR - B.C., YUKON & N.W.T.

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	107.2	104.4	106.7	110.5	114.4
SHELL POST-NEP	90.2	94.1	94.6		93.7
NEB MIDDLE DEMAND CASE	118.8	126.4	134.2	148.5	167.5

TOTAL ENERGY DEMAND

RESIDENTIAL SECTOR - TOTAL CANADA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	1 125.9	1 066.7	1 083.1	1 108.3	1 134.6
IMPERIAL PRE-NEP	1 374.0	1 378.0	1 371.0	1 369.0	1 403.0
NORCEN POST-NEP	969.6	947.5	932.8	961.2	1 018.2
PETRO-CANADA (MAR.12,1981)	1 322.1	1 385.1	1 455.7	1 609.8	1 793.2
SHELL POST-NEP	1 318.3	1 366.3	1 377.3		1 384.3
TEXACO PRE-NEP	1 343.7	1 387.4	1 480.0	1 616.9	1 814.4
NEB MIDDLE DEMAND CASE	1 249.3	1 280.0	1 321.3	1 407.1	1 517.4

TOTAL ENERGY DEMAND

COMMERCIAL SECTOR - NEWFOUNDLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEWFOUNDLAND	14.9	16.3	20.0	24.7	30.4
NEB MIDDLE DEMAND CASE	15.1	16.5	18.3	21.4	25.5

TOTAL ENERGY DEMAND

COMMERCIAL SECTOR - NOVA SCOTIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NOVA SCOTIA POST-NEP	22.6	26.8	31.9	38.1	45.1
NEB MIDDLE DEMAND CASE	24.1	26.2	28.5	33.3	40.8

TOTAL ENERGY DEMAND

COMMERCIAL SECTOR - NEW BRUNSWICK

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEW BRUNSWICK		19.0			
NBEPC	6.9	9.5	12.1		
NEB MIDDLE DEMAND CASE	16.8	18.2	19.8	22.8	27.8

TOTAL ENERGY DEMAND

COMMERCIAL SECTOR - PRINCE EDWARD ISLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEB MIDDLE DEMAND CASE	2.7	2.9	3.4	3.7	4.7

TOTAL ENERGY DEMAND

COMMERCIAL SECTOR - ATLANTIC

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	58.6	60.8	66.3	70.9	83.0
IMPERIAL PRE-NEP	39.0	42.0	46.0	54.0	61.0
SHELL POST-NEP	43.8	47.0	50.9		53.8
NEB MIDDLE DEMAND CASE	58.7	63.8	69.9	81.2	98.8

TOTAL ENERGY DEMAND

COMMERCIAL SECTOR - QUEBEC

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	212.6	210.4	223.2	253.1	286.8
IMPERIAL PRE-NEP	133.0	143.0	155.0	171.0	191.0
TCPL POST-NEP	183.7	176.6	185.4	194.1	209.1
NEB MIDDLE DEMAND CASE	193.4	199.6	209.1	235.5	285.6

TOTAL ENERGY DEMAND

COMMERCIAL SECTOR - ONTARIO

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	321.5	324.1	348.4	393.3	451.0
IMPERIAL PRE-NEP	301.0	329.0	371.0	420.0	478.0
ONTARIO PRE-NEP	281.0	290.0	303.0	317.0	324.0
ONTARIO POST-NEP				300.0	
SHELL POST-NEP	166.2	174.3	179.9		200.1
TCPL POST-NEP	274.3	266.5	280.4	304.5	337.7
NEB MIDDLE DEMAND CASE	353.4	380.2	410.8	463.3	550.2

TOTAL ENERGY DEMAND

COMMERCIAL SECTOR - MANITOBA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	50.4	54.1	58.6	66.4	75.3
MANITOBA POST-NEP	38.6	44.7	51.9	59.7	64.1
TCPL POST-NEP	36.6	35.9	36.7	38.8	41.8
NEB MIDDLE DEMAND CASE	39.1	41.5	46.3	53.7	66.7

TOTAL ENERGY DEMAND

COMMERCIAL SECTOR - SASKATCHEWAN

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	48.9	52.9	60.0	69.9	80.1
SPC	31.3	36.3	39.8	42.9	45.8
TCPL POST-NEP	27.7	27.6	29.5	32.6	36.9
NEB MIDDLE DEMAND CASE	23.0	23.8	25.0	27.3	30.6

TOTAL ENERGY DEMAND

COMMERCIAL SECTOR - ALBERTA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	171.6	191.9	222.5	268.2	315.0
IMPERIAL PRE-NEP	112.0	132.0	155.0	185.0	222.0
SHELL PRE-NEP	73.3	84.8	93.7	101.2	106.3
TCPL VOL.3,HIGH CASE	91.0	100.7	92.9	82.5	85.4
NEB MIDDLE DEMAND CASE	151.9	172.2	189.9	214.0	252.9

TOTAL ENERGY DEMAND

COMMERCIAL SECTOR - BRITISH COLUMBIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
B.C.	81.2	93.0	105.2	119.4	
IMPERIAL PRE-NEP	79.0	88.0	100.0	114.0	133.0
TCPL POST-NEP	70.8	70.0	75.2	83.3	94.5

TOTAL ENERGY DEMAND

COMMERCIAL SECTOR - B.C., YUKON & N.W.T.

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	91.1	93.3	101.5	115.7	132.1
NEB MIDDLE DEMAND CASE	85.3	96.9	112.6	134.0	168.6

TOTAL ENERGY DEMAND

COMMERCIAL SECTOR - TOTAL CANADA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	954.6	987.4	1 080.0	1 240.8	1 423.3
IMPERIAL PRE-NEP	730.0	805.0	905.0	1 033.0	1 186.0
NORCEN POST-NEP	599.4	608.1	599.7	641.9	648.3
PETRO-CANADA (MAR.12,1981)	847.0	919.5	1 114.0	1 366.3	1 654.9
SHELL POST-NEP	739.3	794.2	857.2		947.3
TEXACO PRE-NEP	930.3	1 004.5	1 132.1	1 299.3	1 578.4
NEB MIDDLE DEMAND CASE	904.8	978.0	1 063.5	1 209.0	1 453.0

TOTAL ENERGY DEMAND

PETROCHEMICAL SECTOR - NOVA SCOTIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NOVA SCOTIA POST-NEP	1.1	1.1	1.1	1.1	1.1
NEB MIDDLE DEMAND CASE	1.4	1.4	1.4	1.4	1.4

TOTAL ENERGY DEMAND

PETROCHEMICAL SECTOR - ATLANTIC

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	1.6	1.6	1.6	1.6	1.6
IMPERIAL	PRE-NEP	1.0	1.0	1.0	1.0	1.0
SHELL	POST-NEP	1.3	1.3	1.3		1.3
NEB	MIDDLE DEMAND CASE	1.4	1.4	1.4	1.4	1.4

TOTAL ENERGY DEMAND

PETROCHEMICAL SECTOR - QUEBEC

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	58.1	117.6	117.6	117.6	117.6
IMPERIAL	PRE-NEP	62.0	61.0	69.0	71.0	72.0
SHELL	POST-NEP	67.5	69.6	70.7		75.9
TCPL	POST-NEP	34.8	39.5	59.3	63.9	63.9
NEB	MIDDLE DEMAND CASE	62.8	76.4	76.4	119.4	119.4

TOTAL ENERGY DEMAND

PETROCHEMICAL SECTOR - ONTARIO

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	167.0	169.8	171.1	171.1	171.1
IMPERIAL	PRE-NEP	177.0	197.0	209.0	212.0	223.0
ONTARIO	PRE-NEP	156.0	190.0	232.0	232.0	232.0
SHELL	PRE-NEP	172.2	175.8	175.8	177.9	180.1
TCPL	POST-NEP	109.2	136.5	145.3	146.6	149.2
NEB	MIDDLE DEMAND CASE	138.2	169.3	168.8	167.2	167.0

TOTAL ENERGY DEMAND

PETROCHEMICAL SECTOR - MANITOBA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
PETRO-CANADA	POST-NEP	3.7	3.7	3.7	3.7	3.7
SHELL	PRE-NEP	2.2	2.2	2.2	2.2	2.2
TCPL	POST-NEP	2.4	2.3	2.3	2.3	2.3
NEB	MIDDLE DEMAND CASE	4.2	4.2	4.2	4.2	4.2

TOTAL ENERGY DEMAND

PETROCHEMICAL SECTOR - SASKATCHEWAN

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP		1.1	1.6		

TOTAL ENERGY DEMAND

PETROCHEMICAL SECTOR - ALBERTA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	86.4	180.2	212.9	231.5	232.2
IMPERIAL	PRE-NEP	99.0	193.0	260.0	347.0	464.0
SHELL	POST-NEP	100.4	232.6	359.0		359.0
TCPL	VOL.3,HIGH CASE	114.0	251.3	332.8	350.2	349.6
NEB	MIDDLE DEMAND CASE	177.0	361.9	490.4	533.2	663.6

TOTAL ENERGY DEMAND

PETROCHEMICAL SECTOR - BRITISH COLUMBIA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
IMPERIAL	PRE-NEP	4.0	5.0	5.0	5.0	6.0
TCPL	POST-NEP	4.5	16.0	26.1	34.8	35.7

TOTAL ENERGY DEMAND

PETROCHEMICAL SECTOR - B.C., YUKON & N.W.T.

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	1.7	18.7	18.5	18.5	18.5
SHELL POST-NEP	3.8	34.6	34.6		34.6
NEB MIDDLE DEMAND CASE	5.5	20.9	20.9	29.3	29.3

TOTAL ENERGY DEMAND

PETROCHEMICAL SECTOR - TOTAL CANADA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	314.8	488.7	523.1	540.2	540.9
IMPERIAL PRE-NEP	343.0	456.0	545.0	636.0	766.0
NOVA	224.0	315.0	476.0	671.0	776.0
PETRO-CANADA (MAR.12,1981)	377.6	490.6	541.4	570.4	600.2
SHELL POST-NEP	416.9	554.5	730.8		740.4
TEXACO PRE-NEP	438.4	625.3	716.2	733.7	735.5
TCPL POST-NEP	267.9	543.5	674.3	746.6	749.4
NEB MIDDLE DEMAND CASE	389.0	634.0	762.1	854.7	984.9

TOTAL ENERGY DEMAND

OTHER INDUSTRIAL SECTOR - NEWFOUNDLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEWFOUNDLAND	54.2	60.1	70.0	75.0	80.7
NEB MIDDLE DEMAND CASE	55.0	60.5	65.6	69.9	78.5

TOTAL ENERGY DEMAND

OTHER INDUSTRIAL SECTOR - NOVA SCOTIA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
NOVA SCOTIA	POST-NEP	52.3	55.9	60.1	65.4	71.4
NEB	MIDDLE DEMAND CASE	70.5	77.2	83.3	89.2	100.6

TOTAL ENERGY DEMAND

OTHER INDUSTRIAL SECTOR - NEW BRUNSWICK

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
NEW BRUNSWICK			72.1			
NBEPC		14.8	18.3	21.5		
NEB	MIDDLE DEMAND CASE	63.7	69.5	74.4	79.5	89.6

TOTAL ENERGY DEMAND

OTHER INDUSTRIAL SECTOR - PRINCE EDWARD ISLAND

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
NEB	MIDDLE DEMAND CASE	1.2	1.2	1.4	1.3	1.5

TOTAL ENERGY DEMAND

OTHER INDUSTRIAL SECTOR - ATLANTIC

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	163.7	179.8	211.9	261.8	307.7
IMPERIAL	PRE-NEP	177.0	196.0	218.0	238.0	259.0
SHELL	POST-NEP	113.8	129.0	148.4		193.5
NEB	MIDDLE DEMAND CASE	190.4	208.2	224.5	240.1	270.0

TOTAL ENERGY DEMAND

OTHER INDUSTRIAL SECTOR - QUEBEC

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	524.8	567.0	637.6	728.6	847.1
IMPERIAL PRE-NEP	536.0	577.0	615.0	659.0	692.0
TCPL POST-NEP	469.5	494.8	545.2	589.2	638.6
NEB MIDDLE DEMAND CASE	534.1	544.3	582.6	622.8	703.3

TOTAL ENERGY DEMAND

OTHER INDUSTRIAL SECTOR - ONTARIO

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	865.4	963.2	1 090.0	1 265.4	1 464.3
IMPERIAL PRE-NEP	851.0	951.0	1 072.0	1 197.0	1 302.0
ONTARIO PRE-NEP	911.0	1 114.0	1 271.0	1 401.0	1 543.0
ONTARIO POST-NEP				1 264.0	
SHELL PRE-NEP	477.2	549.8	590.6	705.8	817.2
TCPL POST-NEP	787.7	926.6	1 082.1	1 241.0	1 424.0
NEB MIDDLE DEMAND CASE	840.8	906.9	980.4	1 106.5	1 333.0

TOTAL ENERGY DEMAND

OTHER INDUSTRIAL SECTOR - MANITOBA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	60.0	66.2	72.4	81.6	93.5
MANITOBA POST-NEP	48.0	56.0	66.1	77.9	90.7
SHELL PRE-NEP	46.4	50.3	56.0	62.1	63.6
TCPL POST-NEP	41.2	47.1	55.6	60.5	66.3
NEB MIDDLE DEMAND CASE	48.6	54.7	60.4	67.7	75.7

TOTAL ENERGY DEMAND

OTHER INDUSTRIAL SECTOR - SASKATCHEWAN

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	67.6	105.7	163.6	178.7	205.3
SPC		56.0	67.5	75.7	84.2	94.8
SHELL	PRE-NEP	100.7	115.1	131.1	147.8	164.3
TCPL	POST-NEP	64.1	72.1	86.0	95.1	108.1
NEB	MIDDLE DEMAND CASE	81.8	99.4	113.0	134.5	178.2

TOTAL ENERGY DEMAND

OTHER INDUSTRIAL SECTOR - ALBERTA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	230.5	350.4	537.8	652.6	721.4
IMPERIAL	PRE-NEP	299.0	412.0	543.0	701.0	819.0
SHELL	POST-NEP	364.2	411.7	473.8		579.6
TCPL	VOL.3,HIGH CASE	234.0	325.6	357.5	305.1	288.1
NEB	MIDDLE DEMAND CASE	210.8	306.7	397.9	475.0	594.1

TOTAL ENERGY DEMAND

OTHER INDUSTRIAL SECTOR - BRITISH COLUMBIA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
B.C.		439.3	522.1	572.6	619.9	
IMPERIAL	PRE-NEP	390.0	458.0	550.0	655.0	730.0
TCPL	POST-NEP	282.9	325.1	364.8	400.1	429.3

TOTAL ENERGY DEMAND

OTHER INDUSTRIAL SECTOR - B.C., YUKON & N.W.T.

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	403.7	448.6	508.6	578.9	678.0
NEB MIDDLE DEMAND CASE	419.2	469.1	548.1	625.5	727.2

TOTAL ENERGY DEMAND

OTHER INDUSTRIAL SECTOR - TOTAL CANADA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	2 315.8	2 680.8	3 221.8	3 746.2	4 316.5
IMPERIAL PRE-NEP	2 371.0	2 722.0	3 140.0	3 608.0	3 975.0
PETRO-CANADA (MAR.12,1981)	1 928.4	2 275.8	2 530.6	2 779.7	3 064.9
SHELL POST-NEP	2 505.4	2 924.5	3 318.2		4 069.9
TEXACO PRE-NEP	2 197.2	2 462.1	2 783.9	3 122.7	3 542.7
NEB MIDDLE DEMAND CASE	2 325.6	2 589.3	2 906.9	3 272.1	3 881.7

TOTAL ENERGY DEMAND

TRANSPORTATION SECTOR - NEWFOUNDLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEWFOUNDLAND	39.3	45.4	50.9	56.6	62.1
NEB MIDDLE DEMAND CASE	42.1	43.6	46.0	48.5	53.1

TOTAL ENERGY DEMAND

TRANSPORTATION SECTOR - NOVA SCOTIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NOVA SCOTIA POST-NEP	73.8	40.9	40.9	44.6	48.1
NEB MIDDLE DEMAND CASE	71.5	73.8	77.1	80.9	86.1

TOTAL ENERGY DEMAND

TRANSPORTATION SECTOR - NEW BRUNSWICK

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEW BRUNSWICK		68.0			
NEB MIDDLE DEMAND CASE	57.6	58.7	60.8	63.1	66.6

TOTAL ENERGY DEMAND

TRANSPORTATION SECTOR - PRINCE EDWARD ISLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEB MIDDLE DEMAND CASE	9.0	9.0	9.0	8.8	9.0

TOTAL ENERGY DEMAND

TRANSPORTATION SECTOR - ATLANTIC

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	182.6	192.8	200.8	215.9	231.6
IMPERIAL PRE-NEP	188.0	181.0	172.0	164.0	159.0
SHELL POST-NEP	169.8	160.5	162.6		175.0
NEB MIDDLE DEMAND CASE	179.8	184.8	192.7	201.3	214.6

TOTAL ENERGY DEMAND

TRANSPORTATION SECTOR - QUEBEC

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	449.4	457.8	469.2	490.9	520.6
IMPERIAL PRE-NEP	467.0	448.0	412.0	391.0	372.0
SHELL POST-NEP	433.3	384.3	383.3		413.4
NEB MIDDLE DEMAND CASE	435.9	419.2	417.1	410.7	421.9

TOTAL ENERGY DEMAND

TRANSPORTATION SECTOR - ONTARIO

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	648.2	660.3	683.9	723.8	780.3
IMPERIAL PRE-NEP	663.0	636.0	615.0	588.0	562.0
ONTARIO PRE-NEP	625.0	642.0	682.0	735.0	786.0
ONTARIO POST-NEP				642.0	
SHELL POST-NEP	618.0	547.5	548.4		591.4
NEB MIDDLE DEMAND CASE	642.4	649.9	662.6	675.4	711.5

TOTAL ENERGY DEMAND

TRANSPORTATION SECTOR - MANITOBA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	87.5	89.2	90.8	94.1	97.9
MANITOBA POST-NEP	83.2	76.7	73.7	74.5	78.0
SHELL POST-NEP	75.9	69.9	69.5		76.8
NEB MIDDLE DEMAND CASE	85.0	84.2	84.4	85.0	92.7

TOTAL ENERGY DEMAND

TRANSPORTATION SECTOR - SASKATCHEWAN

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	98.6	104.6	110.3	115.9	124.8
SHELL POST-NEP	72.3	70.1	70.4		78.1
NEB MIDDLE DEMAND CASE	96.3	97.5	102.5	104.9	112.3

TOTAL ENERGY DEMAND

TRANSPORTATION SECTOR - ALBERTA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	269.8	314.9	363.3	413.8	468.0
IMPERIAL PRE-NEP	279.0	329.0	375.0	418.0	433.0
SHELL POST-NEP	226.1	283.1	301.3		383.5
NEB MIDDLE DEMAND CASE	269.3	304.7	345.3	385.7	428.5

TOTAL ENERGY DEMAND

TRANSPORTATION SECTOR - BRITISH COLUMBIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
B.C.	228.6	284.4	305.2	340.7	
IMPERIAL PRE-NEP	250.0	285.0	320.0	357.0	372.0

TOTAL ENERGY DEMAND

TRANSPORTATION SECTOR - B.C., YUKON & N.W.T.

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	245.9	262.1	276.4	294.3	318.0
SHELL POST-NEP	239.0	274.3	289.6		359.1
NEB MIDDLE DEMAND CASE	248.6	281.8	316.6	353.5	403.6

TOTAL ENERGY DEMAND

TRANSPORTATION SECTOR - TOTAL CANADA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
DOME	1 932.1	1 922.0	2 076.7	2 287.1	2 554.9
GULF POST-NEP	1 981.9	2 082.1	2 195.0	2 348.4	2 541.6
IMPERIAL PRE-NEP	2 070.0	2 113.0	2 133.0	2 164.0	2 149.0
NORCEN POST-NEP	1 874.7	1 792.4	1 815.9	1 790.0	1 899.7
PETRO-CANADA (MAR.12,1981)	1 935.1	1 935.8	2 025.3	2 097.1	2 230.5
SHELL POST-NEP	1 834.5	1 791.6	1 825.8		2 049.6
TEXACO PRE-NEP	1 876.9	1 870.6	1 974.8	1 956.3	2 127.6
TEXACO POST-NEP		1 853.0	1 962.0	1 940.0	2 094.0
NEB MIDDLE DEMAND CASE	1 957.2	2 022.3	2 121.2	2 216.5	2 385.2

TOTAL ENERGY DEMAND

OTHER NON-ENERGY USE - NEWFOUNDLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEWFOUNDLAND	2.9	3.4	4.1	5.0	6.1
NEB MIDDLE DEMAND CASE	3.0	3.4	3.8	4.4	5.2

TOTAL ENERGY DEMAND

OTHER NON-ENERGY USE - NOVA SCOTIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NOVA SCOTIA POST-NEP	6.4	5.5	5.6	5.8	5.9
NEB MIDDLE DEMAND CASE	5.6	6.2	7.0	7.9	9.3

TOTAL ENERGY DEMAND

OTHER NON-ENERGY USE - NEW BRUNSWICK

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEW BRUNSWICK		9.9			
NEB MIDDLE DEMAND CASE	8.0	8.9	10.0	11.4	13.4

TOTAL ENERGY DEMAND

OTHER NON-ENERGY USE - PRINCE EDWARD ISLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEB MIDDLE DEMAND CASE	.5	.6	.6	.8	.9

TOTAL ENERGY DEMAND

OTHER NON-ENERGY USE - ATLANTIC

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF PRE-NEP	18.0	20.9	25.1	29.9	33.6
GULF POST-NEP	9.6	11.6	13.7	16.1	18.4
IMPERIAL PRE-NEP	17.0	19.0	21.0	23.0	25.0
SHELL POST-NEP	15.4	17.1	19.0		24.4
NEB MIDDLE DEMAND CASE	17.2	19.1	21.5	24.7	28.7

TOTAL ENERGY DEMAND

OTHER NON-ENERGY USE - QUEBEC

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	61.0	67.6	76.8	89.1	101.5
IMPERIAL PRE-NEP	55.0	63.0	71.0	79.0	88.0
SHELL POST-NEP	56.2	61.9	66.4		76.0
NEB MIDDLE DEMAND CASE	57.8	61.9	67.8	75.2	83.7

TOTAL ENERGY DEMAND

OTHER NON-ENERGY USE - ONTARIO

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	77.2	87.3	101.9	116.4	130.9
IMPERIAL PRE-NEP	66.0	77.0	89.0	104.0	122.0
ONTARIO PRE-NEP	70.0	73.0	77.0	78.0	78.0
SHELL PRE-NEP	73.7	82.6	90.9	97.7	104.5
NEB MIDDLE DEMAND CASE	79.7	90.0	102.4	116.4	133.5

TOTAL ENERGY DEMAND

OTHER NON-ENERGY USE - MANITOBA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	7.7	9.3	10.6	12.3	13.7
SHELL	PRE-NEP	6.7	7.2	7.7	8.3	8.9
NEB	MIDDLE DEMAND CASE	8.4	10.0	11.9	13.8	16.2

TOTAL ENERGY DEMAND

OTHER NON-ENERGY USE - SASKATCHEWAN

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	12.0	15.2	18.2	19.4	20.1
SHELL	PRE-NEP	10.6	11.4	12.2	12.9	13.7
NEB	MIDDLE DEMAND CASE	11.6	12.9	14.3	16.0	18.2

TOTAL ENERGY DEMAND

OTHER NON-ENERGY USE - ALBERTA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	40.5	50.7	56.5	64.3	72.5
IMPERIAL	PRE-NEP	48.0	59.0	73.0	90.0	111.0
SHELL	PRE-NEP	44.9	51.7	57.0	62.8	69.0
NEB	MIDDLE DEMAND CASE	51.9	62.9	74.1	86.0	100.6

TOTAL ENERGY DEMAND

OTHER NON-ENERGY USE - BRITISH COLUMBIA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
B.C.		20.1	21.8	23.4	25.1	
IMPERIAL	PRE-NEP	32.0	35.0	39.0	44.0	50.0

TOTAL ENERGY DEMAND

OTHER NON-ENERGY USE - B.C., YUKON & N.W.T.

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	29.5	34.1	39.9	44.7	49.4
SHELL	POST-NEP	27.6	29.5	31.7		36.6
NEB	MIDDLE DEMAND CASE	32.7	38.0	43.8	49.5	57.1

TOTAL ENERGY DEMAND

OTHER NON-ENERGY USE - TOTAL CANADA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
DOME		265.2	273.0	288.3	312.2	343.7
GULF	POST-NEP	237.6	275.7	317.7	362.2	406.7
IMPERIAL	PRE-NEP	240.0	276.0	317.0	365.0	423.0
PETRO-CANADA	(MAR.12,1981)	187.4	226.4	268.1	312.8	360.3
SHELL	PRE-NEP	235.0	261.5	285.0	308.1	333.1
TEXACO	PRE-NEP	264.4	310.3	368.9	424.2	481.1
TEXACO	POST-NEP		308.0	362.0	417.0	466.0
NEB	MIDDLE DEMAND CASE	259.4	294.9	335.6	381.6	438.0

TOTAL ENERGY DEMAND

OWN USE & LOSSES - NEWFOUNDLAND

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
NEWFOUNDLAND		3.4	4.7	4.3	4.4	5.6
NEB	MIDDLE DEMAND CASE	6.5	6.4	6.1	6.7	7.7

TOTAL ENERGY DEMAND

OWN USE & LOSSES - NOVA SCOTIA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
NEB	MIDDLE DEMAND CASE	16.2	15.8	14.6	15.8	17.1

TOTAL ENERGY DEMAND

OWN USE & LOSSES - NEW BRUNSWICK

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEW BRUNSWICK		19.9			
NBEPC	4.3	5.7	6.4		
NEB MIDDLE DEMAND CASE	19.8	19.3	17.7	18.7	19.2

TOTAL ENERGY DEMAND

OWN USE & LOSSES - PRINCE EDWARD ISLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEB MIDDLE DEMAND CASE	.2	.2	.2	.3	.4

TOTAL ENERGY DEMAND

OWN USE & LOSSES - ATLANTIC

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	56.2	55.7	57.8	60.8	63.9
IMPERIAL PRE-NEP	42.0	39.0	40.0	42.0	45.0
SHELL POST-NEP	37.8	34.5	33.8		35.4
NEB MIDDLE DEMAND CASE	42.6	41.4	36.8	41.4	44.3

TOTAL ENERGY DEMAND

OWN USE & LOSSES - QUEBEC

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	124.9	127.2	132.5	139.0	146.9
IMPERIAL PRE-NEP	107.0	109.0	104.0	103.0	105.0
NEB MIDDLE DEMAND CASE	121.8	122.6	127.8	135.1	141.7

TOTAL ENERGY DEMAND

OWN USE & LOSSES - ONTARIO

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	182.2	203.6	208.3	213.9	241.5
IMPERIAL	PRE-NEP	170.0	167.0	164.0	176.0	183.0
ONTARIO	PRE-NEP	151.0	157.0	166.0	176.0	182.0
SHELL	PRE-NEP	104.2	99.5	88.5	87.8	90.4
NEB	MIDDLE DEMAND CASE	159.5	167.0	170.9	180.3	194.9

TOTAL ENERGY DEMAND

OWN USE & LOSSES - MANITOBA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	30.7	34.9	37.1	37.2	42.4
MANITOBA	POST-NEP	22.1	24.7	26.7	27.9	29.1
NEB	MIDDLE DEMAND CASE	24.7	28.0	27.4	27.7	32.3

TOTAL ENERGY DEMAND

OWN USE & LOSSES - SASKATCHEWAN

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	41.5	49.7	53.8	53.6	61.6
NEB	MIDDLE DEMAND CASE	34.7	49.2	41.8	44.0	52.3

TOTAL ENERGY DEMAND

OWN USE & LOSSES - ALBERTA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	PRE-NEP	114.4	145.7	159.2	167.5	186.5
GULF	POST-NEP	224.8	411.2	505.9	558.6	520.9
IMPERIAL	PRE-NEP	58.0	72.0	57.0	69.0	101.0
NEB	MIDDLE DEMAND CASE	53.9	86.7	81.6	85.0	97.8

TOTAL ENERGY DEMAND

OWN USE & LOSSES - BRITISH COLUMBIA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
IMPERIAL	PRE-NEP	48.0	58.0	47.0	44.0	48.0

TOTAL ENERGY DEMAND

OWN USE & LOSSES - B.C., YUKON & N.W.T.

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	51.3	56.4	61.0	66.8	74.5
NEB	MIDDLE DEMAND CASE	56.2	67.7	57.4	69.7	85.1

TOTAL ENERGY DEMAND

OWN USE & LOSSES - TOTAL CANADA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	PRE-NEP	539.7	621.6	666.2	697.0	763.7
GULF	POST-NEP	711.6	938.3	1 056.1	1 130.1	1 151.7
IMPERIAL	PRE-NEP	479.0	509.0	470.0	489.0	533.0
IMPERIAL	POST-NEP	479.0		480.0		530.0
SHELL	PRE-NEP	528.7	572.8	510.7	525.3	556.5
SHELL	POST-NEP		608.0	510.7		556.5
TEXACO	PRE-NEP	678.5	719.5	779.3	850.1	948.1
TEXACO	POST-NEP		594.0	623.0	657.0	718.0
NEB	MIDDLE DEMAND CASE	493.2	562.5	545.4	582.9	648.2

TOTAL DEMAND FOR

COAL - NEWFOUNDLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
COAL ASSN. PRE-NEP			5.6	5.6	5.6
NEWFOUNDLAND	2.1	2.1	2.1	2.1	2.1
NEB MIDDLE DEMAND CASE	2.3	2.7	3.3	9.4	4.7

TOTAL DEMAND FOR

COAL - NOVA SCOTIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
COAL ASSN. PRE-NEP	54.0	68.6	100.4	92.2	114.6
COAL ASSN. POST-NEP			128.4	165.0	198.6
NOVA SCOTIA PRE-NEP	61.1	82.6	119.8	114.5	129.7
NOVA SCOTIA POST-NEP		84.2	124.1	140.0	157.0
NEB MIDDLE DEMAND CASE	68.8	94.4	143.8	164.5	190.5

TOTAL DEMAND FOR

COAL - NEW BRUNSWICK

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
COAL ASSN. PRE-NEP	16.8	16.8	16.8	16.8	30.8
COAL ASSN. POST-NEP			44.8	72.8	103.6
NEW BRUNSWICK		16.5			
NBEPC	8.8	8.6	12.3		
NEB MIDDLE DEMAND CASE	30.7	24.7	21.3	30.2	22.5

TOTAL DEMAND FOR

COAL - ATLANTIC

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	52.2	217.6	251.4	262.4	266.8
IMPERIAL	PRE-NEP	65.0	98.0	122.0	124.0	126.0
SHELL	PRE-NEP	46.9	60.7	65.3	57.9	52.5
NEB	MIDDLE DEMAND CASE	101.9	121.6	167.5	208.1	226.1

TOTAL DEMAND FOR

COAL - QUEBEC

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
COAL ASSN.	PRE-NEP	16.8	14.0	19.6	39.2	47.6
GULF	POST-NEP	21.6	25.0	29.6	34.3	39.7
IMPERIAL	PRE-NEP	15.0	16.0	13.0	14.0	15.0
SHELL	PRE-NEP	25.0	32.0	34.6	37.7	40.8
TCPL	VOL.3,HIGH CASE	23.3	31.4	40.6	52.2	62.1
NEB	MIDDLE DEMAND CASE	24.8	25.0	25.1	22.2	19.1

TOTAL DEMAND FOR

COAL - ONTARIO

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
CPA				716.0		
COAL ASSN.	PRE-NEP	600.8	594.5	600.7	706.4	813.6
COAL ASSN.	POST-NEP				715.2	831.2
GULF	POST-NEP	467.3	574.9	622.7	844.4	1 102.1
IMPERIAL	PRE-NEP	614.0	582.0	624.0	740.0	896.0
ONTARIO	PRE-NEP	578.0	700.0	794.0	801.0	838.0
SHELL	PRE-NEP	514.3	512.0	538.6	548.8	570.1
NEB	MIDDLE DEMAND CASE	592.1	564.3	622.7	746.3	810.0

TOTAL DEMAND FOR

COAL - MANITOBA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
COAL ASSN.	PRE-NEP	6.0	6.0	6.0	18.7	18.7
GULF	POST-NEP	13.7	23.1	22.2	18.0	13.7
MANITOBA	POST-NEP	6.2	7.8	9.2	10.8	12.7
SHELL	PRE-NEP	9.0	9.1	8.9	9.0	8.7
TCPL	POST-NEP	5.8	6.6	7.4	8.1	9.1
NEB	MIDDLE DEMAND CASE	5.3	4.6	3.9	3.9	3.9

TOTAL DEMAND FOR

COAL - SASKATCHEWAN

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
COAL ASSN.	PRE-NEP	102.3	147.2	182.9	181.3	222.0
GULF	POST-NEP	83.7	111.9	184.3	242.3	290.3
SPC		82.8	119.6	143.8	138.1	162.3
SHELL	PRE-NEP	90.5	96.9	101.3	112.6	131.7
NEB	MIDDLE DEMAND CASE	81.3	108.0	111.3	142.2	157.2

TOTAL DEMAND FOR

COAL - ALBERTA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
COAL ASSN.	PRE-NEP	215.8	336.8	512.9	765.0	1 032.1
COAL ASSN.	POST-NEP			561.2	822.5	1 101.1
GULF	POST-NEP	205.4	263.2	366.4	500.2	678.6
IMPERIAL	PRE-NEP	200.0	333.0	483.0	636.0	848.0
SHELL	PRE-NEP	196.5	258.8	324.7	388.7	455.2
NEB	MIDDLE DEMAND CASE	205.3	299.0	365.7	502.4	611.7

TOTAL DEMAND FOR

COAL - BRITISH COLUMBIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
B.C.	6.6	9.4	11.6	14.7	
COAL ASSN. PRE-NEP	14.3	14.3	159.5	334.6	490.2
COAL ASSN. POST-NEP				394.0	624.4
IMPERIAL PRE-NEP	7.0	8.0	8.0	8.0	50.0

TOTAL DEMAND FOR

COAL - B.C., YUKON & N.W.T.

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	11.5	14.0	17.0	21.0	23.9
SHELL PRE-NEP	8.5	9.3	9.3	9.3	9.3
NEB MIDDLE DEMAND CASE	8.6	22.9	39.3	86.4	223.4

TOTAL DEMAND FOR

COAL - TOTAL CANADA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
CPA	915.0		1 396.0		
COAL ASSN. PRE-NEP	1 026.8	1 198.4	1 604.4	2 159.8	2 775.2
COAL ASSN. POST-NEP			1 708.7	2 414.3	3 152.8
GULF POST-NEP	855.6	1 229.6	1 493.5	1 922.4	2 415.0
IMPERIAL PRE-NEP	994.0	1 151.0	1 399.0	1 696.0	2 132.0
IMPERIAL POST-NEP	993.0		1 409.0		2 129.0
NORCEN POST-NEP	980.2	1 143.1	1 284.4	1 455.4	1 642.8
PETRO-CANADA (MAR.12,1981)	870.3	1 124.5	1 441.6	1 729.3	2 059.5
SHELL PRE-NEP	890.6	978.8	1 082.7	1 164.1	1 268.2
TEXACO PRE-NEP	987.9	1 161.3	1 328.8	1 534.2	1 767.2
NEB MIDDLE DEMAND CASE	1 019.2	1 145.4	1 336.4	1 711.3	2 051.4

TOTAL DEMAND FOR

LPG - NEWFOUNDLAND

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
NEB	MIDDLE DEMAND CASE	1.0	.9	1.3	1.4	1.7

TOTAL DEMAND FOR

LPG - NOVA SCOTIA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
NEB	MIDDLE DEMAND CASE	2.0	2.0	2.8	3.1	3.6

TOTAL DEMAND FOR

LPG - NEW BRUNSWICK

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
NEW BRUNSWICK			4.9			
NEB	MIDDLE DEMAND CASE	2.2	2.2	3.0	3.4	3.8

TOTAL DEMAND FOR

LPG - PRINCE EDWARD ISLAND

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
NEB	MIDDLE DEMAND CASE	.3	.3	.4	.4	.5

TOTAL DEMAND FOR

LPG - ATLANTIC

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	6.4	6.5	6.9	7.2	7.8
IMPERIAL	PRE-NEP	8.0	8.0	8.0	9.0	9.0
SHELL	PRE-NEP	3.6	4.1	4.5	4.8	5.1
NEB	MIDDLE DEMAND CASE	5.4	5.3	7.5	8.3	9.4

TOTAL DEMAND FOR

LPG - QUEBEC

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	13.1	12.9	14.0	15.3	17.3
IMPERIAL	PRE-NEP	27.0	22.0	21.0	21.0	21.0
SHELL	PRE-NEP	12.6	13.6	14.1	14.8	15.5
NEB	MIDDLE DEMAND CASE	19.6	21.4	23.1	24.6	26.9

TOTAL DEMAND FOR

LPG - ONTARIO

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	26.8	26.9	27.7	29.3	31.4
IMPERIAL	PRE-NEP	36.0	49.0	63.0	64.0	67.0
SHELL	PRE-NEP	17.2	17.4	17.2	17.3	17.3
NEB	MIDDLE DEMAND CASE	26.9	36.8	39.6	39.9	42.2

TOTAL DEMAND FOR

LPG - MANITOBA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	3.3	3.6	3.9	4.2	4.8
MANITOBA	POST-NEP	2.1	1.3	1.3	1.2	1.3
SHELL	PRE-NEP	5.3	5.7	5.9	6.2	6.3
NEB	MIDDLE DEMAND CASE	2.3	2.4	3.6	3.9	4.3

TOTAL DEMAND FOR

LPG - SASKATCHEWAN

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	5.2	18.6	25.4	5.2	5.3
SHELL	PRE-NEP	4.5	4.9	5.1	5.3	5.5
NEB	MIDDLE DEMAND CASE	5.8	6.1	7.1	7.5	8.3

TOTAL DEMAND FOR

LPG - ALBERTA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	43.0	107.2	184.9	144.8	72.7
IMPERIAL	PRE-NEP	30.0	35.0	44.0	59.0	76.0
SHELL	PRE-NEP	16.3	18.2	19.7	20.7	21.9
NEB	MIDDLE DEMAND CASE	20.1	22.2	69.0	114.4	117.8

TOTAL DEMAND FOR

LPG - BRITISH COLUMBIA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
B.C.		2.8	8.0	7.9	8.3	
IMPERIAL	PRE-NEP	8.0	12.0	21.0	22.0	25.0

TOTAL DEMAND FOR

LPG - B.C., YUKON & N.W.T.

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	7.2	8.1	10.4	11.8	13.3
SHELL	PRE-NEP	8.2	9.0	9.3	9.6	9.6
NEB	MIDDLE DEMAND CASE	9.0	8.6	10.1	11.9	14.3

TOTAL DEMAND FOR

LPG - TOTAL CANADA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
CPA		100.0		188.0		
DOME		135.0	150.7	159.9	173.8	189.6
GULF	POST-NEP	104.9	183.8	272.9	217.7	152.8
IMPERIAL	PRE-NEP	122.0	139.0	170.0	189.0	211.0
PETRO-CANADA	EXHIBIT 62-10	131.4	190.0	210.0		215.0
TEXACO	PRE-NEP	119.2	145.6	157.1	157.1	152.0
NEB	MIDDLE DEMAND CASE	89.1	102.6	159.9	210.3	223.0

TOTAL DEMAND FOR

ETHANE - ALBERTA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
IMPERIAL	PRE-NEP	32.0	56.0	96.0	130.0	164.0
SHELL	PRE-NEP	35.1	35.1	70.2	70.2	70.2
SHELL	POST-NEP		35.1	140.4		140.4
TCPL	VOL.3,HIGH CASE	29.6	74.9	115.1	120.2	120.2
NEB	MIDDLE DEMAND CASE	38.6	101.2	135.0	135.0	135.0

TOTAL DEMAND FOR

ETHANE - TOTAL CANADA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
DOME	27.7	89.5	136.9	127.3	127.3
IMPERIAL PRE-NEP	36.0	62.0	98.0	130.0	164.0
NOVA	38.6	101.2	138.0	138.0	138.0
SHELL PRE-NEP	35.1	35.1	70.2	70.2	70.2
SHELL POST-NEP		35.1	140.4		140.4
TCPL VOL.3,HIGH CASE	29.6	74.9	115.1	120.2	120.2
NEB MIDDLE DEMAND CASE	38.6	101.2	135.0	135.0	135.0

TOTAL DEMAND FOR

NATURAL GAS - NOVA SCOTIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
DOME		27.0	22.0	26.0	30.0
ICG SCOTIA		37.0	40.5		
NOVA SCOTIA POST-NEP		53.7	39.4	47.6	54.2
TQM POST-NEP		36.4	30.0	37.2	42.4
NEB MIDDLE DEMAND CASE		8.9	30.3	40.7	50.5

TOTAL DEMAND FOR

NATURAL GAS - NEW BRUNSWICK

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
DOME		12.0	21.0	28.0	33.0
ICG(NB)		50.1	55.0		
TQM POST-NEP		57.5	43.2	52.2	60.5
NEB MIDDLE DEMAND CASE	.1	16.6	33.5	38.6	45.8

TOTAL DEMAND FOR

NATURAL GAS - ATLANTIC

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	.2	20.4	47.7	64.7	68.8
IMPERIAL PRE-NEP			90.0	144.0	197.0
NOVA		35.0	48.0	71.0	91.0
PETRO-CANADA (MAR.12,1981)	.2	62.9	74.2	107.0	134.0
SHELL POST-NEP		22.8	45.4		79.1
TQM POST-NEP		93.9	73.2	89.2	102.9
NEB MIDDLE DEMAND CASE	.1	25.5	63.8	79.3	96.3

TOTAL DEMAND FOR

NATURAL GAS - QUEBEC

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
DOME	105.0	197.0	281.0	351.0	423.0
GMI EXISTING AND EXTENSION MARKETS	97.9	255.2	281.8	317.0	357.1
GULF POST-NEP	102.4	163.7	191.6	214.7	241.5
IMPERIAL PRE-NEP	103.0	202.0	298.0	334.0	366.0
NOVA	102.0	186.0	312.0	404.0	487.0
PETRO-CANADA (MAR.12,1981)	101.6	213.6	303.3	352.5	379.6
SHELL POST-NEP		202.6	288.3		472.6
TCPL POST-NEP	104.9	296.3	340.2	376.2	401.4
TQM POST-NEP	105.6	291.5	318.5	351.3	383.8
NEB MIDDLE DEMAND CASE	104.3	198.1	282.6	318.6	359.0

TOTAL DEMAND FOR

NATURAL GAS - ONTARIO

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
CPA			927.0		
DOME	686.0	757.0	705.0	692.0	715.0
GULF POST-NEP	714.9	822.8	901.1	962.9	1 049.2
IMPERIAL PRE-NEP	728.0	839.0	923.0	965.0	999.0
NOVA	749.0	790.0	852.0	947.0	1 053.0
ONTARIO PRE-NEP	749.0	828.0	882.0	913.0	931.0
PETRO-CANADA (MAR.12,1981)	737.5	923.7	1 001.8	1 083.6	1 153.6
SHELL PRE-NEP	699.2	794.3	949.6	1 085.2	1 218.3
SHELL POST-NEP		817.4	997.1		1 280.9
TCPL POST-NEP	686.0	845.4	981.1	1 061.4	1 134.7
UNION	816.0	913.0	1 042.0	1 158.0	1 229.0
NEB MIDDLE DEMAND CASE	732.7	850.3	936.5	1 031.4	1 184.4

TOTAL DEMAND FOR

NATURAL GAS - MANITOBA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
DOME	65.0	70.0	65.0	62.0	60.0
GULF POST-NEP	82.7	88.5	91.9	92.8	99.7
MANITOBA POST-NEP	78.8	93.9	105.7	117.7	126.6
NOVA	68.0	69.0	73.0	80.0	87.0
PETRO-CANADA (MAR.12,1981)	78.0	93.2	101.8	109.8	115.8
SHELL PRE-NEP	71.5	76.4	81.3	86.7	87.7
TCPL POST-NEP	65.0	70.4	75.8	79.9	84.7
NEB MIDDLE DEMAND CASE	80.3	87.6	90.8	98.1	111.3

TOTAL DEMAND FOR

NATURAL GAS - SASKATCHEWAN

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
DOME	96.0	91.0	93.0	94.0	98.0
GULF POST-NEP	137.1	155.2	192.1	217.0	242.7
NOVA	99.0	103.0	115.0	135.0	159.0
PETRO-CANADA (MAR.12,1981)	136.6	143.8	158.8	173.5	187.9
SPC	112.1	119.0	123.0	129.9	137.3
SHELL PRE-NEP	105.9	117.0	125.5	136.3	148.2
TCPL POST-NEP	99.3	105.4	113.2	120.1	129.4
NEB MIDDLE DEMAND CASE	125.1	149.7	149.0	164.6	204.2

TOTAL DEMAND FOR

NATURAL GAS - ALBERTA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
DOME	500.0	783.0	853.0	810.0	802.0
GULF POST-NEP	677.4	963.3	1 163.0	1 380.2	1 469.7
IMPERIAL PRE-NEP	527.0	632.0	685.0	786.0	827.0
NOVA	490.0	557.0	614.0	698.0	778.0
PETRO-CANADA (MAR.12,1981)	547.1	663.0	760.3	896.6	1 047.4
SHELL PRE-NEP	571.1	624.3	664.5	713.3	755.5
SHELL POST-NEP		708.1	769.4		860.4
TCPL VOL.3,HIGH CASE	580.9	783.4	852.7	810.2	801.9
NEB MIDDLE DEMAND CASE	549.7	756.0	870.5	921.5	1 045.6

TOTAL DEMAND FOR

NATURAL GAS - BRITISH COLUMBIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
B.C.		220.0	245.0	280.0	
DOME	166.0	197.0	224.0	250.0	280.0
IMPERIAL PRE-NEP	189.0	210.0	213.0	224.0	236.0
NOVA	165.0	176.0	196.0	225.0	259.0
PETRO-CANADA (MAR.12,1981)	188.2	233.7	247.0	279.3	319.6
SHELL PRE-NEP	170.6	198.1	214.9	230.6	244.5
TCPL POST-NEP	158.1	178.2	209.2	238.5	257.8
WESTCOAST B.C.MAINLAND	186.8	239.3	263.0	302.2	

TOTAL DEMAND FOR

NATURAL GAS - B.C., YUKON & N.W.T.

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	173.4	229.7	264.8	292.5	324.1
SHELL POST-NEP		239.0	265.1		307.1
NEB MIDDLE DEMAND CASE	189.1	255.3	271.4	341.3	409.7

TOTAL DEMAND FOR

NATURAL GAS - TOTAL CANADA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
CPA	1 775.0		2 364.0		
DOME	1 756.0	2 332.0	2 482.0	2 540.0	2 671.0
GULF POST-NEP	1 887.9	2 443.4	2 851.8	3 224.7	3 495.8
IMPERIAL PRE-NEP	1 751.0	2 094.0	2 405.0	2 649.0	2 814.0
NORCEN POST-NEP	1 684.5	2 116.5	2 309.5	2 523.8	2 723.2
NOVA	1 833.0	2 156.0	2 404.0	2 766.0	3 145.0
PETRO-CANADA (MAR.12,1981)	1 789.6	2 335.0	2 648.6	3 001.6	3 336.2
SHELL PRE-NEP	1 862.8	2 181.4	2 639.4	2 875.8	3 127.6
SHELL POST-NEP		2 354.7	2 899.3		3 447.4
TEXACO POST-NEP	2 006.3	2 385.0	2 815.0	3 224.0	3 668.0
TCPL POST-NEP	1 829.5	2 546.3	2 804.5	2 934.2	3 081.6
NEB MIDDLE DEMAND CASE	1 781.3	2 322.6	2 664.3	2 954.5	3 410.5

TOTAL DEMAND FOR

ELECTRICITY - NEWFOUNDLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEWFOUNDLAND	29.9	37.4	46.1	54.4	64.4
NEB MIDDLE DEMAND CASE	31.2	37.1	44.1	52.2	61.9

TOTAL DEMAND FOR

ELECTRICITY - NOVA SCOTIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NOVA SCOTIA PRE-NEP	21.0	23.9	27.7	32.3	37.9
NOVA SCOTIA POST-NEP		22.6	26.3	31.0	36.5
NEB MIDDLE DEMAND CASE	25.6	31.5	36.9	44.8	56.1

TOTAL DEMAND FOR

ELECTRICITY - NEW BRUNSWICK

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
NEW BRUNSWICK			38.0			
NBEPC		42.3	53.5	64.4		
NEB	MIDDLE DEMAND CASE	30.9	39.3	45.5	51.7	60.0

TOTAL DEMAND FOR

ELECTRICITY - PRINCE EDWARD ISLAND

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
NEB	MIDDLE DEMAND CASE	2.0	2.5	3.0	3.8	4.7

TOTAL DEMAND FOR

ELECTRICITY - ATLANTIC

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	91.1	124.8	166.9	211.1	256.1
IMPERIAL	PRE-NEP	85.0	112.0	143.0	163.0	181.0
SHELL	PRE-NEP	91.1	106.4	120.9	134.5	145.9
NEB	MIDDLE DEMAND CASE	89.7	110.5	129.5	152.5	182.7

TOTAL DEMAND FOR

ELECTRICITY - QUEBEC

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	404.3	513.5	633.8	746.1	848.0
IMPERIAL	PRE-NEP	387.0	458.0	515.0	562.0	600.0
SHELL	PRE-NEP	416.3	481.6	529.1	565.6	603.9
TCPL	VOL.3,HIGH CASE	362.1	406.4	469.9	528.0	591.6
NEB	MIDDLE DEMAND CASE	418.1	496.7	566.3	634.3	734.8

TOTAL DEMAND FOR

ELECTRICITY - ONTARIO

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	376.2	455.6	553.0	667.4	780.9
IMPERIAL PRE-NEP	378.0	466.0	555.0	648.0	741.0
ONTARIO PRE-NEP	398.0	465.0	528.0	594.0	672.0
SHELL PRE-NEP	380.4	422.2	460.2	499.3	539.4
TCPL POST-NEP	325.7	374.1	441.0	513.2	581.5
UNION	373.0	494.0	583.0	669.0	731.0
NEB MIDDLE DEMAND CASE	393.2	441.6	490.4	570.0	679.8

TOTAL DEMAND FOR

ELECTRICITY - MANITOBA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	51.3	60.1	67.1	75.8	85.5
MANITOBA POST-NEP	47.2	57.6	67.4	77.9	85.9
SHELL PRE-NEP	50.2	53.9	57.4	60.3	63.3
TCPL POST-NEP	35.3	40.3	47.2	52.0	57.8
NEB MIDDLE DEMAND CASE	51.3	56.8	62.6	69.5	81.2

TOTAL DEMAND FOR

ELECTRICITY - SASKATCHEWAN

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	34.2	44.5	63.4	78.9	91.8
SPC	34.6	47.2	57.9	67.1	78.0
SHELL PRE-NEP	36.8	41.4	45.4	49.6	54.2
TCPL POST-NEP	27.7	32.6	39.2	44.6	52.1
NEB MIDDLE DEMAND CASE	33.1	40.7	45.1	50.9	62.7

TOTAL DEMAND FOR

ELECTRICITY - ALBERTA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	82.7	98.1	138.1	191.8	251.9
IMPERIAL	PRE-NEP	84.0	128.0	171.0	219.0	269.0
SHELL	PRE-NEP	85.7	103.2	131.6	151.1	172.9
TCPL	VOL.2,SEPT. 1980	75.5	90.5	127.8	156.2	183.3
NEB	MIDDLE DEMAND CASE	83.8	114.5	143.1	178.6	227.6

TOTAL DEMAND FOR

ELECTRICITY - BRITISH COLUMBIA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
IMPERIAL	PRE-NEP	149.0	178.0	210.0	242.0	275.0
TCPL	POST-NEP	129.6	151.0	179.4	209.4	239.6

TOTAL DEMAND FOR

ELECTRICITY - B.C., YUKON & N.W.T.

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	157.1	178.4	210.6	246.6	289.9
SHELL	PRE-NEP	162.2	182.5	200.0	215.4	231.0
NEB	MIDDLE DEMAND CASE	155.1	188.8	219.9	259.2	315.9

TOTAL DEMAND FOR

ELECTRICITY - TOTAL CANADA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	1 197.0	1 475.4	1 833.0	2 218.2	2 604.0
IMPERIAL PRE-NEP	1 193.0	1 463.0	1 730.0	1 986.0	2 233.0
PETRO-CANADA (MAR.12,1981)	1 073.4	1 316.2	1 600.0	1 970.9	2 388.1
SHELL PRE-NEP	1 222.7	1 391.2	1 544.7	1 675.1	1 809.2
TEXACO PRE-NEP	1 222.1	1 506.8	1 763.3	2 091.3	2 469.8
NEB MIDDLE DEMAND CASE	1 224.1	1 449.5	1 656.8	1 915.1	2 284.6

TOTAL DEMAND FOR

HOG FUEL AND PULPING LIQUOR - NEWFOUNDLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEB MIDDLE DEMAND CASE	5.1	6.3	8.1	10.4	12.4

TOTAL DEMAND FOR

HOG FUEL AND PULPING LIQUOR - NOVA SCOTIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NOVA SCOTIA PRE-NEP	3.2	3.2	3.2	3.3	3.3
NEB MIDDLE DEMAND CASE	4.4	5.5	6.5	7.2	8.2

TOTAL DEMAND FOR

HOG FUEL AND PULPING LIQUOR - NEW BRUNSWICK

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEW BRUNSWICK		29.1			
NEB MIDDLE DEMAND CASE	13.6	16.9	19.8	22.5	25.2

TOTAL DEMAND FOR

HOG FUEL AND PULPING LIQUOR - ATLANTIC

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	22.4	29.2	37.5	47.5	61.9
IMPERIAL	PRE-NEP	22.0	24.0	26.0	28.0	32.0
NEB	MIDDLE DEMAND CASE	23.0	28.7	34.4	40.1	45.8

TOTAL DEMAND FOR

HOG FUEL AND PULPING LIQUOR - QUEBEC

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	41.4	54.5	70.8	90.2	118.2
IMPERIAL	PRE-NEP	47.0	55.0	63.0	69.0	74.0
NEB	MIDDLE DEMAND CASE	44.8	57.8	70.9	84.0	97.0

TOTAL DEMAND FOR

HOG FUEL AND PULPING LIQUOR - ONTARIO

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	49.6	57.3	67.4	81.2	96.3
IMPERIAL	PRE-NEP	50.0	55.0	58.0	61.0	63.0
NEB	MIDDLE DEMAND CASE	47.1	52.3	64.0	73.5	84.5

TOTAL DEMAND FOR

HOG FUEL AND PULPING LIQUOR - MANITOBA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	9.8	11.0	12.4	14.2	16.9
NEB	MIDDLE DEMAND CASE	4.6	6.4	8.3	10.1	12.0

TOTAL DEMAND FOR

HOG FUEL AND PULPING LIQUOR - SASKATCHEWAN

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	3.3	3.6	4.0	4.4	5.1
NEB	MIDDLE DEMAND CASE	7.0	8.0	8.5	9.0	9.5

TOTAL DEMAND FOR

HOG FUEL AND PULPING LIQUOR - ALBERTA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	12.3	13.3	14.7	16.3	18.9
IMPERIAL	PRE-NEP	26.0	26.0	26.0	26.0	26.0
NEB	MIDDLE DEMAND CASE	13.5	16.4	19.3	22.1	25.0

TOTAL DEMAND FOR

HOG FUEL AND PULPING LIQUOR - BRITISH COLUMBIA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
B.C.		196.4	232.5	244.3	248.0	
IMPERIAL	PRE-NEP	171.0	209.0	269.0	343.0	385.0

TOTAL DEMAND FOR

HOG FUEL AND PULPING LIQUOR - B.C., YUKON & N.W.T.

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	164.1	178.1	196.6	218.1	252.9
SHELL	PRE-NEP	158.8	203.0	224.4	233.6	259.5
NEB	MIDDLE DEMAND CASE	177.9	211.0	242.6	267.9	294.6

TOTAL DEMAND FOR

HOG FUEL AND PULPING LIQUOR - TOTAL CANADA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
CPA		315.0		443.0		
GULF	POST-NEP	302.9	346.9	403.4	472.0	570.2
IMPERIAL	PRE-NEP	316.0	369.0	443.0	527.0	580.0
TEXACO	PRE-NEP	332.2	404.9	484.0	539.9	612.7
NEB	MIDDLE DEMAND CASE	317.9	380.6	448.0	506.7	568.4

TOTAL DEMAND FOR

OTHER RENEWABLE ENERGY - NEWFOUNDLAND

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
NEB	MIDDLE DEMAND CASE	1.8	2.3	5.3	8.2	12.0

TOTAL DEMAND FOR

OTHER RENEWABLE ENERGY - NOVA SCOTIA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
NOVA SCOTIA	PRE-NEP	6.9	10.7	11.8	12.5	13.1
NOVA SCOTIA	POST-NEP		2.4	2.4	2.4	2.4
NEB	MIDDLE DEMAND CASE	2.3	3.2	6.4	9.7	14.4

TOTAL DEMAND FOR

OTHER RENEWABLE ENERGY - NEW BRUNSWICK

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
NEW BRUNSWICK			10.6			
NBEPC		16.3	15.5	17.7		
NEB	MIDDLE DEMAND CASE	2.6	3.2	5.9	8.5	12.3

TOTAL DEMAND FOR

OTHER RENEWABLE ENERGY - PRINCE EDWARD ISLAND

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
NEB	MIDDLE DEMAND CASE	.6	.6	1.2	1.8	2.3

TOTAL DEMAND FOR

OTHER RENEWABLE ENERGY - ATLANTIC

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	PRE-NEP			.5	5.5	12.0
GULF	POST-NEP	7.8	7.5	7.8	8.9	18.4
IMPERIAL	PRE-NEP	4.0	4.0	4.0	7.0	14.0
SHELL	PRE-NEP	3.3	2.8	3.3	4.6	6.9
NEB	MIDDLE DEMAND CASE	7.6	9.4	18.5	28.4	40.7

TOTAL DEMAND FOR

OTHER RENEWABLE ENERGY - QUEBEC

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	PRE-NEP			1.0	15.5	34.6
GULF	POST-NEP	7.9	7.9	8.9	22.5	40.6
IMPERIAL	PRE-NEP	6.0	6.0	6.0	12.0	32.0
SHELL	PRE-NEP	3.9	3.3	5.1	7.1	11.2
TCPL	VOL.3,HIGH CASE					.7
NEB	MIDDLE DEMAND CASE			19.6	41.6	70.0

TOTAL DEMAND FOR

OTHER RENEWABLE ENERGY - ONTARIO

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF PRE-NEP			1.8	24.0	53.7
GULF POST-NEP	6.5	7.2	9.3	30.9	59.5
IMPERIAL PRE-NEP	4.0	4.0	6.0	16.0	49.0
ONTARIO PRE-NEP	16.0	31.0	37.0	44.0	48.0
ONTARIO POST-NEP				252.0	
SHELL PRE-NEP	2.3	2.3	6.0	11.0	19.4
TCPL POST-NEP				.1	2.0
NEB MIDDLE DEMAND CASE			29.3	58.3	98.7

TOTAL DEMAND FOR

OTHER RENEWABLE ENERGY - MANITOBA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF PRE-NEP			.2	3.5	7.7
GULF POST-NEP			.3	3.4	7.4
SHELL PRE-NEP	.4	.3	.6	1.0	1.8
TCPL POST-NEP					.2
NEB MIDDLE DEMAND CASE			3.2	6.7	11.7

TOTAL DEMAND FOR

OTHER RENEWABLE ENERGY - SASKATCHEWAN

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF PRE-NEP			.3	3.1	7.0
GULF POST-NEP		.1	.4	3.1	6.8
SHELL PRE-NEP	.2		.2	.5	1.0
TCPL POST-NEP					.3
NEB MIDDLE DEMAND CASE			2.9	6.4	10.5

TOTAL DEMAND FOR

OTHER RENEWABLE ENERGY - ALBERTA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF PRE-NEP			.9	14.7	33.7
GULF POST-NEP	1.1	1.1	1.9	3.8	6.6
IMPERIAL PRE-NEP	1.0	1.0	1.0	3.0	15.0
SHELL PRE-NEP	.7	.6	2.3	4.6	9.1
TCPL VOL.2,SEPT. 1980			.1	.1	.1

TOTAL DEMAND FOR

OTHER RENEWABLE ENERGY - BRITISH COLUMBIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
IMPERIAL PRE-NEP	1.0	1.0	1.0	7.0	22.0
TCPL POST-NEP					.6

TOTAL DEMAND FOR

OTHER RENEWABLE ENERGY - B.C., YUKON & N.W.T.

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF PRE-NEP			.5	7.2	16.0
GULF POST-NEP	2.9	3.1	3.7	10.0	18.4
SHELL PRE-NEP	1.1	1.1	2.3	4.1	7.1
NEB MIDDLE DEMAND CASE			13.8	22.9	35.2

TOTAL DEMAND FOR

OTHER RENEWABLE ENERGY - TOTAL CANADA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
CPA			43.0		
GULF PRE-NEP		.1	5.3	73.5	164.8
GULF POST-NEP	26.3	26.8	32.3	85.9	157.6
IMPERIAL PRE-NEP	17.0	17.0	19.0	54.0	153.0
IMPERIAL POST-NEP	16.0		20.0		155.0
PETRO-CANADA (MAR.12,1981)	15.0	56.5	115.7	158.7	195.0
SHELL PRE-NEP	11.8	10.3	19.8	32.9	56.6
TEXACO PRE-NEP	7.5	42.6	105.6	163.7	269.0
NEB MIDDLE DEMAND CASE	7.6	9.4	87.3	164.4	266.6

TOTAL DEMAND FOR

MOTOR GASOLINE - NEWFOUNDLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEWFOUNDLAND	23.1	26.0	29.0	31.8	34.3
SHELL PRE-NEP	22.7	23.3	22.2	20.6	21.3
SHELL POST-NEP		19.7	17.8		14.0
NEB MIDDLE DEMAND CASE	22.4	21.3	20.0	18.8	17.8

TOTAL DEMAND FOR

MOTOR GASOLINE - NOVA SCOTIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NOVA SCOTIA PRE-NEP	41.2	35.3	34.4	37.1	39.4
NEB MIDDLE DEMAND CASE	44.6	42.5	39.8	37.4	35.5

TOTAL DEMAND FOR

MOTOR GASOLINE - NEW BRUNSWICK

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEW BRUNSWICK		42.9			
NEB MIDDLE DEMAND CASE	39.1	37.2	34.9	32.8	31.2

TOTAL DEMAND FOR

MOTOR GASOLINE - PRINCE EDWARD ISLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEB MIDDLE DEMAND CASE	7.0	6.7	6.3	5.9	5.6

TOTAL DEMAND FOR

MOTOR GASOLINE - ATLANTIC

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	119.3	117.8	108.7	104.7	102.9
IMPERIAL PRE-NEP	118.0	105.0	85.0	69.0	56.0
PETRO-CANADA (MAR.12,1981)	112.9	101.9	96.9	88.1	87.8
SHELL PRE-NEP	116.0	116.2	103.6	102.8	108.0
SHELL POST-NEP		97.8	86.6		68.7
TEXACO PRE-NEP	114.3	107.3	109.6	99.6	98.8
NEB MIDDLE DEMAND CASE	113.1	107.7	100.9	94.8	90.1

TOTAL DEMAND FOR

MOTOR GASOLINE - QUEBEC

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	308.4	293.8	277.3	261.5	254.1
IMPERIAL PRE-NEP	318.0	290.0	241.0	206.0	177.0
PETRO-CANADA (MAR.12,1981)	299.7	266.2	251.4	226.6	222.9
SHELL PRE-NEP	316.7	287.1	254.3	226.2	223.1
SHELL POST-NEP		242.9	207.6		149.3
TEXACO PRE-NEP	324.1	298.4	302.1	271.5	265.4
NEB MIDDLE DEMAND CASE	304.3	271.5	249.3	223.4	207.8

TOTAL DEMAND FOR

MOTOR GASOLINE - ONTARIO

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	468.7	445.0	422.6	401.3	393.6
IMPERIAL PRE-NEP	482.0	435.0	377.0	324.0	279.0
ONTARIO PRE-NEP	461.0	425.5	419.5	425.2	438.8
PETRO-CANADA (MAR.12,1981)	457.4	415.8	398.7	365.3	366.1
SHELL PRE-NEP	471.9	432.3	404.1	382.6	391.0
SHELL POST-NEP		363.4	313.1		219.3
TEXACO PRE-NEP	487.8	457.6	468.3	425.8	422.3
NEB MIDDLE DEMAND CASE	465.6	435.9	399.0	365.0	340.7

TOTAL DEMAND FOR

MOTOR GASOLINE - MANITOBA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	58.6	55.0	51.7	48.4	46.2
MANITOBA POST-NEP	55.5	49.2	43.0	40.1	39.1
PETRO-CANADA (MAR.12,1981)	57.3	51.2	48.4	43.8	43.5
SHELL PRE-NEP	58.6	57.7	53.9	52.8	53.1
SHELL POST-NEP		49.5	42.7		34.0
TEXACO PRE-NEP	55.0	50.9	51.5	46.4	45.7
NEB MIDDLE DEMAND CASE	56.0	51.1	45.1	39.8	37.0

TOTAL DEMAND FOR

MOTOR GASOLINE - SASKATCHEWAN

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	74.1	72.9	71.2	68.4	68.3
PETRO-CANADA (MAR.12,1981)	72.6	65.7	62.1	56.2	55.7
SHELL PRE-NEP	73.9	71.1	68.3	75.4	79.6
SHELL POST-NEP		66.2	60.7		56.5
TEXACO PRE-NEP	71.9	66.4	66.2	58.8	57.1
NEB MIDDLE DEMAND CASE	71.2	66.6	63.1	58.3	54.8

TOTAL DEMAND FOR

MOTOR GASOLINE - ALBERTA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	176.1	187.1	194.0	198.5	202.2
IMPERIAL PRE-NEP	178.0	195.0	200.0	200.0	181.0
PETRO-CANADA (MAR.12,1981)	176.0	181.6	191.5	191.2	205.7
SHELL PRE-NEP	180.0	203.6	188.4	164.9	168.4
SHELL POST-NEP		203.5	184.9		161.9
TEXACO PRE-NEP	157.8	161.3	178.1	171.7	178.3
NEB MIDDLE DEMAND CASE	174.6	184.1	188.3	195.1	199.9

TOTAL DEMAND FOR

MOTOR GASOLINE - BRITISH COLUMBIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
B.C.	136.5	170.5	175.9	189.3	
IMPERIAL PRE-NEP	153.0	168.0	173.0	176.0	160.0
PETRO-CANADA (MAR.12,1981)	144.2	135.3	135.7	129.4	134.4

TOTAL DEMAND FOR

MOTOR GASOLINE - B.C., YUKON & N.W.T.

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
CHEVRON CANADA	153.1	182.2	195.5	193.9	193.1
GULF POST-NEP	152.2	150.6	141.8	133.9	129.7
SHELL PRE-NEP	155.2	170.1	165.4	156.5	156.8
SHELL POST-NEP		167.9	157.9		152.7
TEXACO PRE-NEP	149.0	144.1	154.1	145.8	149.7
NEB MIDDLE DEMAND CASE	155.9	163.2	166.1	173.1	184.9

TOTAL DEMAND FOR

MOTOR GASOLINE - TOTAL CANADA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
DOME	1 352.7	1 217.4	1 208.0	1 277.1	1 375.3
GULF POST-NEP	1 357.5	1 322.2	1 267.3	1 216.8	1 197.1
IMPERIAL PRE-NEP	1 392.0	1 333.0	1 208.0	1 101.0	967.0
IMPERIAL POST-NEP	1 379.0		1 199.0		957.0
NORCEN PRE-NEP	1 378.0	1 345.6	1 327.7	1 210.2	1 201.5
PETRO-CANADA (MAR.12,1981)	1 320.2	1 217.6	1 184.6	1 100.6	1 116.1
SHELL PRE-NEP	1 372.6	1 338.6	1 238.4	1 161.5	1 180.4
SHELL POST-NEP		1 191.7	1 053.6		814.1
TEXACO PRE-NEP	1 360.3	1 286.2	1 330.1	1 219.8	1 221.7
NEB MIDDLE DEMAND CASE	1 340.7	1 279.9	1 211.8	1 149.5	1 115.3

TOTAL DEMAND FOR

AVIATION FUEL - NEWFOUNDLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEWFOUNDLAND	9.2	11.1	12.7	14.5	16.5
SHELL PRE-NEP	10.5	11.4	13.3	15.9	18.9
NEB MIDDLE DEMAND CASE	9.4	11.0	12.7	14.5	18.0

TOTAL DEMAND FOR

AVIATION FUEL - NOVA SCOTIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NOVA SCOTIA PRE-NEP	5.0	5.6	6.5	7.5	8.7
NEB MIDDLE DEMAND CASE	4.1	4.7	5.3	6.1	7.5

TOTAL DEMAND FOR

AVIATION FUEL - NEW BRUNSWICK

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEW BRUNSWICK		2.0			
NEB MIDDLE DEMAND CASE	1.8	2.1	2.5	2.8	3.5

TOTAL DEMAND FOR

AVIATION FUEL - PRINCE EDWARD ISLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEB MIDDLE DEMAND CASE	.4	.4	.5	.5	.6

TOTAL DEMAND FOR

AVIATION FUEL - ATLANTIC

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	16.3	18.3	21.6	25.9	30.1
IMPERIAL PRE-NEP	16.0	17.0	19.0	22.0	24.0
PETRO-CANADA (MAR.12,1981)	16.5	17.9	19.6	23.7	30.1
SHELL PRE-NEP	17.5	18.6	21.7	25.8	30.8
TEXACO PRE-NEP	14.2	14.6	14.4	14.8	17.7
NEB MIDDLE DEMAND CASE	15.6	18.1	20.9	23.9	29.6

TOTAL DEMAND FOR

AVIATION FUEL - QUEBEC

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	37.8	41.0	44.5	52.2	60.8
IMPERIAL PRE-NEP	38.0	40.0	44.0	46.0	51.0
PETRO-CANADA (MAR.12,1981)	38.3	40.7	44.5	53.2	67.0
SHELL PRE-NEP	36.2	40.3	48.0	57.8	69.3
TEXACO PRE-NEP	40.4	40.4	39.3	39.9	47.5
NEB MIDDLE DEMAND CASE	36.9	40.9	44.5	48.3	56.3

TOTAL DEMAND FOR

AVIATION FUEL - ONTARIO

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	53.2	59.5	67.9	84.5	104.0
IMPERIAL PRE-NEP	56.0	63.0	74.0	86.0	92.0
ONTARIO PRE-NEP	44.6	51.9	64.8	74.0	79.5
PETRO-CANADA (MAR.12,1981)	53.1	57.8	64.2	77.9	100.0
SHELL PRE-NEP	51.7	60.7	72.5	86.4	103.8
TEXACO PRE-NEP	46.7	48.3	48.2	50.2	61.4
NEB MIDDLE DEMAND CASE	53.7	61.6	70.0	79.3	97.0

TOTAL DEMAND FOR

AVIATION FUEL - MANITOBA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	10.4	11.7	12.6	14.5	16.4
MANITOBA POST-NEP	10.5	9.8	11.4	13.3	15.4
PETRO-CANADA (MAR.12,1981)	10.8	11.5	12.6	15.0	19.2
SHELL PRE-NEP	9.3	9.5	11.2	13.4	16.4
TEXACO PRE-NEP	8.6	8.6	8.3	8.4	9.9
NEB MIDDLE DEMAND CASE	9.1	10.1	11.3	12.6	16.0

TOTAL DEMAND FOR

AVIATION FUEL - SASKATCHEWAN

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	4.0	4.9	5.7	7.1	8.5
PETRO-CANADA (MAR.12,1981)	4.0	4.4	4.7	5.7	7.1
SHELL PRE-NEP	3.6	3.9	4.4	5.4	6.6
TEXACO PRE-NEP	3.6	3.7	3.8	4.0	4.9
NEB MIDDLE DEMAND CASE	3.9	4.5	5.3	6.2	7.8

TOTAL DEMAND FOR

AVIATION FUEL - ALBERTA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	27.2	37.8	49.6	65.4	83.6
IMPERIAL PRE-NEP	28.0	39.0	57.0	78.0	92.0
PETRO-CANADA (MAR.12,1981)	28.4	35.1	42.8	56.6	78.0
SHELL PRE-NEP	24.8	32.6	39.5	47.6	57.5
TEXACO PRE-NEP	20.3	22.5	23.9	26.0	32.9
NEB MIDDLE DEMAND CASE	28.0	33.7	40.2	47.8	61.2

TOTAL DEMAND FOR

AVIATION FUEL - BRITISH COLUMBIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
B.C.	23.1	29.2	34.2	42.0	
IMPERIAL PRE-NEP	28.0	36.0	47.0	62.0	72.0
PETRO-CANADA (MAR.12,1981)	26.4	29.7	34.4	43.4	57.6

TOTAL DEMAND FOR

AVIATION FUEL - B.C., YUKON & N.W.T.

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
CHEVRON CANADA	25.9	32.6	38.8	44.4	49.2
GULF POST-NEP	28.7	32.4	37.1	43.7	51.8
SHELL PRE-NEP	27.3	32.4	39.3	47.3	57.2
TEXACO PRE-NEP	26.3	27.2	27.5	29.0	35.9
NEB MIDDLE DEMAND CASE	27.9	36.7	43.2	50.9	64.5

TOTAL DEMAND FOR

AVIATION FUEL - TOTAL CANADA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
DOME	158.2	172.5	200.5	230.2	252.5
GULF POST-NEP	177.3	205.6	239.0	293.1	355.4
IMPERIAL PRE-NEP	184.0	218.0	267.0	320.0	359.0
IMPERIAL POST-NEP	184.0		263.0		357.0
NORCEN PRE-NEP	161.7	162.9	149.1	147.6	175.8
PETRO-CANADA (MAR.12,1981)	177.5	197.2	222.7	275.4	359.1
SHELL PRE-NEP	171.3	199.1	237.9	285.0	342.7
TEXACO PRE-NEP	160.7	165.8	165.7	172.6	210.9
NEB MIDDLE DEMAND CASE	175.1	205.8	235.3	269.0	332.4

TOTAL DEMAND FOR

LIGHT FUEL OIL AND KEROSENE - NEWFOUNDLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEWFOUNDLAND	24.0	22.5	20.9	19.9	19.8
SHELL PRE-NEP	24.2	24.1	23.8	23.4	22.7
NEB MIDDLE DEMAND CASE	23.2	23.4	20.0	18.0	17.3

TOTAL DEMAND FOR

LIGHT FUEL OIL AND KEROSENE - NOVA SCOTIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NOVA SCOTIA PRE-NEP	44.1	43.5	44.0	44.9	45.7
NOVA SCOTIA POST-NEP		37.1	37.3	37.8	38.5
NEB MIDDLE DEMAND CASE	45.2	41.0	30.8	25.5	23.3

TOTAL DEMAND FOR

LIGHT FUEL OIL AND KEROSENE - NEW BRUNSWICK

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEW BRUNSWICK		33.2			
NEB MIDDLE DEMAND CASE	29.8	24.4	13.4	9.4	6.4

TOTAL DEMAND FOR

LIGHT FUEL OIL AND KEROSENE - PRINCE EDWARD ISLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEB MIDDLE DEMAND CASE	7.0	6.9	6.9	6.6	6.7

TOTAL DEMAND FOR

LIGHT FUEL OIL AND KEROSENE - ATLANTIC

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	97.1	64.6	45.9	36.5	28.8
IMPERIAL PRE-NEP	98.0	82.0	59.0	43.0	34.0
PETRO-CANADA (MAR.12,1981)	99.2	94.5	78.4	70.3	60.9
SHELL PRE-NEP	111.4	111.8	110.8	108.6	105.1
SHELL POST-NEP		104.8	97.8		84.8
TEXACO PRE-NEP	112.0	120.8	116.8	124.8	136.8
NEB MIDDLE DEMAND CASE	105.2	95.7	71.1	59.5	53.7

TOTAL DEMAND FOR

LIGHT FUEL OIL AND KEROSENE - QUEBEC

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	227.2	129.8	96.6	68.1	46.2
IMPERIAL PRE-NEP	221.0	152.0	111.0	85.0	65.0
PETRO-CANADA (MAR.12,1981)	230.0	180.2	139.5	120.0	109.7
SHELL PRE-NEP	223.6	173.0	137.8	111.1	90.2
SHELL POST-NEP		155.7	112.1		66.7
TEXACO PRE-NEP	230.3	158.1	103.7	71.5	51.3
NEB MIDDLE DEMAND CASE	221.1	145.4	91.8	70.9	60.6

TOTAL DEMAND FOR

LIGHT FUEL OIL AND KEROSENE - ONTARIO

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	193.9	130.9	95.5	65.9	48.6
IMPERIAL PRE-NEP	188.0	111.0	69.0	58.0	50.0
PETRO-CANADA (MAR.12,1981)	188.6	137.5	104.7	91.3	86.6
SHELL PRE-NEP	200.0	177.9	162.4	146.4	130.0
SHELL POST-NEP		151.6	105.9		53.4
TEXACO PRE-NEP	204.7	162.3	137.5	119.5	98.5
NEB MIDDLE DEMAND CASE	202.8	140.5	94.7	66.6	57.8

TOTAL DEMAND FOR

LIGHT FUEL OIL AND KEROSENE - MANITOBA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	12.3	8.8	7.5	7.0	6.4
MANITOBA POST-NEP	12.8	8.7	7.1	5.3	5.3
PETRO-CANADA (MAR.12,1981)	12.4	6.0	2.9	1.4	1.2
SHELL PRE-NEP	12.6	10.7	9.0	7.6	6.4
TEXACO PRE-NEP	11.2	7.6	4.0	3.1	2.1
NEB MIDDLE DEMAND CASE	10.8	8.8	7.2	5.2	3.4

TOTAL DEMAND FOR

LIGHT FUEL OIL AND KEROSENE - SASKATCHEWAN

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	14.0	9.8	8.2	6.6	5.2
PETRO-CANADA (MAR.12,1981)	14.5	7.9	2.8	1.4	1.6
SHELL PRE-NEP	14.3	12.5	10.5	8.9	7.3
TEXACO PRE-NEP	15.2	10.8	6.6	3.5	.5
NEB MIDDLE DEMAND CASE	13.5	11.1	9.3	8.3	7.6

TOTAL DEMAND FOR

LIGHT FUEL OIL AND KEROSENE - ALBERTA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	7.6	6.1	5.7	5.4	5.1
IMPERIAL PRE-NEP	8.0	7.0	6.0	5.0	4.0
PETRO-CANADA (MAR.12,1981)	6.1	4.9	4.1	4.4	4.6
SHELL PRE-NEP	11.1	9.8	8.5	7.6	7.4
TEXACO PRE-NEP	11.1	9.2	7.2	6.6	6.9
NEB MIDDLE DEMAND CASE	7.4	5.0	4.5	3.9	3.4

TOTAL DEMAND FOR

LIGHT FUEL OIL AND KEROSENE - BRITISH COLUMBIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
B.C.		37.3	36.8	35.5	
IMPERIAL PRE-NEP	36.0	30.0	26.0	23.0	20.0
PETRO-CANADA (MAR.12,1981)	41.0	30.4	28.9	33.7	39.8

TOTAL DEMAND FOR

LIGHT FUEL OIL AND KEROSENE - B.C., YUKON & N.W.T.

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
CHEVRON CANADA	40.4	37.9	37.5	36.8	36.1
GULF POST-NEP	45.4	33.1	27.5	23.0	19.7
SHELL PRE-NEP	47.7	43.7	41.4	39.3	36.8
SHELL POST-NEP		40.0	30.9		18.9
TEXACO PRE-NEP	50.4	43.9	37.0	36.4	36.0
NEB MIDDLE DEMAND CASE	46.3	38.1	36.3	30.7	29.9

TOTAL DEMAND FOR

LIGHT FUEL OIL AND KEROSENE - TOTAL CANADA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
DOME	644.5	524.2	505.6	324.4	267.6
GULF POST-NEP	597.5	383.0	286.7	212.4	159.9
IMPERIAL PRE-NEP	587.0	412.0	297.0	237.0	192.0
IMPERIAL POST-NEP	583.0		297.0		192.0
PETRO-CANADA (MAR.12,1981)	591.7	461.5	361.2	322.5	304.5
SHELL PRE-NEP	621.1	539.7	481.0	429.8	383.7
SHELL POST-NEP		485.3	375.1		245.5
TEXACO PRE-NEP	638.5	513.2	409.7	342.7	332.3
NEB MIDDLE DEMAND CASE	606.9	444.8	314.9	245.1	216.4

TOTAL DEMAND FOR

DIESEL FUEL OIL - NEWFOUNDLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEWFOUNDLAND	16.3	18.3	20.6	23.0	25.4
SHELL PRE-NEP	17.6	22.5	26.4	30.6	35.3
NEB MIDDLE DEMAND CASE	19.3	22.2	25.0	27.8	31.1

TOTAL DEMAND FOR

DIESEL FUEL OIL - NOVA SCOTIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NOVA SCOTIA PRE-NEP	24.9	33.4	39.1	42.3	45.7
NEB MIDDLE DEMAND CASE	26.2	31.9	37.3	43.2	49.5

TOTAL DEMAND FOR

DIESEL FUEL OIL - NEW BRUNSWICK

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEW BRUNSWICK		18.6			
NEB MIDDLE DEMAND CASE	16.4	20.5	24.3	28.6	33.2

TOTAL DEMAND FOR

DIESEL FUEL OIL - PRINCE EDWARD ISLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEB MIDDLE DEMAND CASE	2.2	2.7	3.1	3.4	3.9

TOTAL DEMAND FOR

DIESEL FUEL OIL - ATLANTIC

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	54.9	66.5	82.9	99.4	114.2
IMPERIAL PRE-NEP	59.0	65.0	77.0	88.0	99.0
PETRO-CANADA (MAR.12,1981)	62.2	71.5	71.8	72.5	70.2
SHELL PRE-NEP	59.4	71.7	84.3	98.1	113.2
TEXACO PRE-NEP	62.9	69.6	74.1	80.5	89.5
NEB MIDDLE DEMAND CASE	63.9	76.9	89.6	102.8	117.4

TOTAL DEMAND FOR

DIESEL FUEL OIL - QUEBEC

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	113.9	141.8	172.5	207.2	239.5
IMPERIAL	PRE-NEP	116.0	131.0	145.0	157.0	165.0
PETRO-CANADA	(MAR.12,1981)	104.0	110.7	122.1	133.9	130.9
SHELL	PRE-NEP	108.6	132.2	161.4	194.4	235.4
TEXACO	PRE-NEP	75.2	82.8	96.3	113.3	139.0
NEB	MIDDLE DEMAND CASE	110.3	122.9	136.0	148.8	167.8

TOTAL DEMAND FOR

DIESEL FUEL OIL - ONTARIO

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	135.0	164.8	206.1	253.1	299.1
IMPERIAL	PRE-NEP	137.0	148.0	163.0	179.0	193.0
ONTARIO	PRE-NEP	94.3	116.6	139.1	165.0	187.6
PETRO-CANADA	(MAR.12,1981)	127.3	146.5	158.0	160.8	156.8
SHELL	PRE-NEP	133.1	165.6	207.1	254.7	314.9
TEXACO	PRE-NEP	100.4	114.8	130.1	157.6	201.1
NEB	MIDDLE DEMAND CASE	129.8	159.9	206.6	252.6	308.5

TOTAL DEMAND FOR

DIESEL FUEL OIL - MANITOBA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	30.2	36.2	42.5	49.7	56.6
MANITOBA	POST-NEP	22.9	23.4	25.0	26.8	29.2
PETRO-CANADA	(MAR.12,1981)	33.1	36.4	37.7	39.7	41.8
SHELL	PRE-NEP	28.9	33.8	39.1	44.9	51.5
TEXACO	PRE-NEP	30.5	33.9	37.2	41.6	47.8
NEB	MIDDLE DEMAND CASE	29.1	33.7	39.0	44.7	53.6

TOTAL DEMAND FOR

DIESEL FUEL OIL - SASKATCHEWAN

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	41.4	52.3	64.2	74.8	87.0
PETRO-CANADA (MAR.12,1981)	48.3	54.5	58.9	66.1	69.8
SHELL PRE-NEP	44.4	57.2	70.2	79.9	90.4
TEXACO PRE-NEP	39.3	44.4	46.6	52.3	60.6
NEB MIDDLE DEMAND CASE	44.6	55.9	66.5	76.4	90.9

TOTAL DEMAND FOR

DIESEL FUEL OIL - ALBERTA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	108.0	139.3	175.3	215.6	258.8
IMPERIAL PRE-NEP	111.0	168.0	240.0	338.0	420.0
PETRO-CANADA (MAR.12,1981)	100.7	136.7	192.0	255.9	288.1
SHELL PRE-NEP	114.9	178.6	234.8	281.8	338.3
SHELL POST-NEP		164.2	224.8		338.3
TEXACO PRE-NEP	79.8	88.6	105.3	122.9	150.4
NEB MIDDLE DEMAND CASE	105.4	136.9	180.9	219.3	256.2

TOTAL DEMAND FOR

DIESEL FUEL OIL - BRITISH COLUMBIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
IMPERIAL PRE-NEP	97.0	118.0	141.0	168.0	195.0
PETRO-CANADA (MAR.12,1981)	96.7	115.2	122.8	135.5	141.4

TOTAL DEMAND FOR

DIESEL FUEL OIL - B.C., YUKON & N.W.T.

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
CHEVRON CANADA	93.4	115.6	136.7	156.2	173.7
GULF POST-NEP	98.8	117.8	140.6	165.3	192.0
SHELL PRE-NEP	107.0	136.8	166.1	195.5	229.9
SHELL POST-NEP		136.8	165.1		229.9
TEXACO PRE-NEP	85.4	84.7	91.9	105.7	129.5
NEB MIDDLE DEMAND CASE	97.8	123.2	154.1	185.7	219.2

TOTAL DEMAND FOR

DIESEL FUEL OIL - TOTAL CANADA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
DOME	533.1	650.2	813.0	986.3	1 177.7
GULF POST-NEP	582.2	718.7	884.0	1 064.9	1 247.4
IMPERIAL PRE-NEP	601.0	723.0	872.0	1 051.0	1 209.0
IMPERIAL POST-NEP	594.0		861.0		1 196.0
PETRO-CANADA (MAR.12,1981)	572.4	671.4	763.3	864.3	899.0
SHELL PRE-NEP	596.6	776.4	963.5	1 149.8	1 374.0
SHELL POST-NEP		761.9	953.5		1 374.0
TEXACO PRE-NEP	470.4	519.1	584.3	677.6	818.0
NEB MIDDLE DEMAND CASE	580.9	709.2	872.9	1 030.7	1 213.6

TOTAL DEMAND FOR

HEAVY FUEL OIL - NEWFOUNDLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEWFOUNDLAND	54.5	63.9	37.7	40.4	43.3
SHELL PRE-NEP	44.2	43.9	48.4	55.5	62.0
NEB MIDDLE DEMAND CASE	52.7	51.3	23.8	27.5	18.6

TOTAL DEMAND FOR

HEAVY FUEL OIL - NOVA SCOTIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NOVA SCOTIA PRE-NEP	68.4	20.6	21.4	22.7	24.5
NOVA SCOTIA POST-NEP		17.9	18.4	19.9	21.3
NEB MIDDLE DEMAND CASE	63.0	58.7	25.1	18.9	16.4

TOTAL DEMAND FOR

HEAVY FUEL OIL - NEW BRUNSWICK

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEW BRUNSWICK		73.1			
NEB MIDDLE DEMAND CASE	74.7	37.4	27.4	40.1	26.1

TOTAL DEMAND FOR

HEAVY FUEL OIL - PRINCE EDWARD ISLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEB MIDDLE DEMAND CASE	2.8	2.7	2.7	3.0	2.4

TOTAL DEMAND FOR

HEAVY FUEL OIL - ATLANTIC

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	225.1	104.9	76.6	64.2	58.3
IMPERIAL PRE-NEP	191.0	180.0	100.0	81.0	73.0
PETRO-CANADA (MAR.12,1981)	191.2	131.6	91.3	81.8	75.3
SHELL PRE-NEP	230.7	200.4	217.4	227.0	244.0
SHELL POST-NEP		185.8	187.2		188.4
TEXACO PRE-NEP	107.9	99.8	62.5	53.3	60.1
NEB MIDDLE DEMAND CASE	193.1	150.1	79.0	89.6	63.5

TOTAL DEMAND FOR

HEAVY FUEL OIL - QUEBEC

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	237.9	150.3	99.1	77.6	72.1
IMPERIAL PRE-NEP	276.0	217.0	140.0	120.0	100.0
PETRO-CANADA (MAR.12,1981)	250.8	191.1	151.3	141.7	152.9
SHELL PRE-NEP	229.9	213.2	91.1	92.2	88.6
TEXACO PRE-NEP	257.8	196.5	150.0	117.7	93.7
NEB MIDDLE DEMAND CASE	235.8	147.1	86.6	70.5	64.0

TOTAL DEMAND FOR

HEAVY FUEL OIL - ONTARIO

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	132.0	69.5	40.2	37.4	40.8
IMPERIAL PRE-NEP	158.0	116.0	93.0	87.0	81.0
PETRO-CANADA (MAR.12,1981)	151.8	118.0	85.5	89.4	106.7
SHELL PRE-NEP	138.8	149.2	52.7	56.9	47.3
TEXACO PRE-NEP	114.9	117.6	109.0	105.3	96.2
NEB MIDDLE DEMAND CASE	132.8	105.1	69.7	66.1	66.9

TOTAL DEMAND FOR

HEAVY FUEL OIL - MANITOBA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	5.3	4.3	3.5	3.2	2.9
PETRO-CANADA (MAR.12,1981)	4.7	1.8	1.8	3.0	4.6
SHELL PRE-NEP	5.4	5.5	5.7	5.7	5.2
TEXACO PRE-NEP	3.6	2.9	2.7	2.3	1.2
NEB MIDDLE DEMAND CASE	2.2	2.1	1.9	1.7	1.6

TOTAL DEMAND FOR

HEAVY FUEL OIL - SASKATCHEWAN

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	.6	.7	.8	1.0	1.1
PETRO-CANADA (MAR.12,1981)	1.0	1.4	3.7	3.6	2.7
SHELL PRE-NEP	.7	.6	.6	.7	.6
TEXACO PRE-NEP	1.0	.7	3.0	3.0	1.5
NEB MIDDLE DEMAND CASE	2.4	2.2	1.9	1.9	2.0

TOTAL DEMAND FOR

HEAVY FUEL OIL - ALBERTA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	.9	.8	.6	.6	.7
IMPERIAL PRE-NEP	1.0	1.0	1.0	1.0	1.0
PETRO-CANADA (MAR.12,1981)	.7	.8	1.0	1.3	1.7
SHELL PRE-NEP	3.3	3.3	3.3	3.3	3.3
TEXACO PRE-NEP	3.4	3.6	3.6	5.3	4.2
NEB MIDDLE DEMAND CASE	.8	.8	.6	.8	.7

TOTAL DEMAND FOR

HEAVY FUEL OIL - BRITISH COLUMBIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
B.C.	46.1	35.0	34.4	34.5	
IMPERIAL PRE-NEP	49.0	38.0	29.0	21.0	18.0
PETRO-CANADA (MAR.12,1981)	43.3	14.0	10.4	10.6	10.4

TOTAL DEMAND FOR

HEAVY FUEL OIL - B.C., YUKON & N.W.T.

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
CHEVRON CANADA	52.5	53.5	36.6	36.6	36.6
GULF POST-NEP	55.3	37.7	25.5	22.8	24.7
SHELL PRE-NEP	50.7	52.6	54.0	55.7	57.3
SHELL POST-NEP		46.0	44.7		42.8
TEXACO PRE-NEP	51.8	46.1	35.5	33.2	29.2
NEB MIDDLE DEMAND CASE	59.0	25.6	21.4	23.5	27.9

TOTAL DEMAND FOR

HEAVY FUEL OIL - TOTAL CANADA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
DOME	707.0	622.1	513.7	496.2	502.7
GULF POST-NEP	657.3	368.0	246.4	205.3	199.9
IMPERIAL PRE-NEP	685.0	563.0	375.0	319.0	281.0
IMPERIAL POST-NEP	618.0		341.0		247.0
PETRO-CANADA (MAR.12,1981)	643.5	458.6	344.9	331.5	354.4
SHELL PRE-NEP	659.8	625.2	425.1	441.8	446.6
SHELL POST-NEP		604.4	385.9		376.8
TEXACO PRE-NEP	540.8	471.4	366.7	320.6	285.4
NEB MIDDLE DEMAND CASE	626.0	433.3	261.2	254.1	226.8

TOTAL DEMAND FOR

OTHER PETROLEUM PRODUCTS - NEWFOUNDLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEWFOUNDLAND	3.0	3.6	4.2	5.1	6.2
SHELL PRE-NEP	2.1	2.3	2.4	2.5	2.7
NEB MIDDLE DEMAND CASE	6.1	6.3	6.2	6.9	7.6

TOTAL DEMAND FOR

OTHER PETROLEUM PRODUCTS - NOVA SCOTIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NOVA SCOTIA PRE-NEP	7.5	7.7	7.9	8.2	8.4
NOVA SCOTIA POST-NEP		6.6	6.7	6.9	7.0
NEB MIDDLE DEMAND CASE	19.6	19.2	17.9	19.1	20.2

TOTAL DEMAND FOR

OTHER PETROLEUM PRODUCTS - NEW BRUNSWICK

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEW BRUNSWICK		11.2			
NEB MIDDLE DEMAND CASE	23.7	23.4	21.9	23.7	25.3

TOTAL DEMAND FOR

OTHER PETROLEUM PRODUCTS - PRINCE EDWARD ISLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEB MIDDLE DEMAND CASE	.5	.6	.6	.8	.9

TOTAL DEMAND FOR

OTHER PETROLEUM PRODUCTS - ATLANTIC

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	11.2	13.2	15.3	17.7	20.0
IMPERIAL PRE-NEP	43.0	43.0	42.0	44.0	46.0
PETRO-CANADA (MAR.12,1981)	17.7	19.7	23.2	26.7	30.4
SHELL PRE-NEP	16.3	18.1	19.9	21.9	25.3
TEXACO PRE-NEP	15.7	18.7	21.8	25.2	28.6
NEB MIDDLE DEMAND CASE	50.0	49.4	45.8	50.6	53.8

TOTAL DEMAND FOR

OTHER PETROLEUM PRODUCTS - QUEBEC

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	118.1	184.2	193.4	205.7	218.1
IMPERIAL	PRE-NEP	153.0	161.0	181.0	191.0	201.0
PETRO-CANADA	(MAR.12,1981)	108.1	123.2	132.7	140.5	149.2
SHELL	PRE-NEP	123.6	131.3	136.9	144.8	151.8
TEXACO	PRE-NEP	110.0	153.3	163.6	174.5	184.6
NEB	MIDDLE DEMAND CASE	191.3	197.0	194.6	245.3	254.0

TOTAL DEMAND FOR

OTHER PETROLEUM PRODUCTS - ONTARIO

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	215.6	228.5	244.4	258.9	273.4
IMPERIAL	PRE-NEP	283.0	301.0	318.0	337.0	363.0
PETRO-CANADA	(MAR.12,1981)	170.7	187.0	208.9	233.4	261.1
SHELL	PRE-NEP	212.6	225.0	233.4	242.4	251.4
TEXACO	PRE-NEP	236.8	283.5	350.1	367.5	385.2
NEB	MIDDLE DEMAND CASE	276.1	293.2	301.1	315.5	332.7

TOTAL DEMAND FOR

OTHER PETROLEUM PRODUCTS - MANITOBA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	7.7	9.3	10.6	12.3	13.7
PETRO-CANADA	(MAR.12,1981)	7.1	8.9	10.5	12.4	14.2
SHELL	PRE-NEP	6.5	6.9	7.5	8.2	8.8
TEXACO	PRE-NEP	7.1	8.8	10.5	12.3	14.2
NEB	MIDDLE DEMAND CASE	13.5	15.1	17.0	18.9	21.8

TOTAL DEMAND FOR

OTHER PETROLEUM PRODUCTS - SASKATCHEWAN

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	12.0	16.3	19.8	19.4	20.1
PETRO-CANADA	(MAR.12,1981)	11.0	15.0	17.8	21.0	24.3
SHELL	PRE-NEP	10.4	11.3	12.1	12.8	13.5
TEXACO	PRE-NEP	12.0	15.0	17.9	21.0	24.3
NEB	MIDDLE DEMAND CASE	17.5	19.0	20.7	22.7	25.5

TOTAL DEMAND FOR

OTHER PETROLEUM PRODUCTS - ALBERTA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	40.9	102.8	119.8	120.9	117.3
IMPERIAL	PRE-NEP	67.0	114.0	136.0	168.0	234.0
PETRO-CANADA	(MAR.12,1981)	39.4	99.1	107.5	89.0	70.5
SHELL	PRE-NEP	44.8	85.1	90.5	96.3	102.5
TEXACO	PRE-NEP	46.0	102.1	113.4	125.5	137.8
NEB	MIDDLE DEMAND CASE	76.7	124.8	148.7	159.7	303.7

TOTAL DEMAND FOR

OTHER PETROLEUM PRODUCTS - BRITISH COLUMBIA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
B.C.		20.1	21.8	23.4	25.1	
IMPERIAL	PRE-NEP	52.0	58.0	62.0	68.0	74.0
PETRO-CANADA	(MAR.12,1981)	23.0	26.1	30.9	35.8	41.0

TOTAL DEMAND FOR

OTHER PETROLEUM PRODUCTS - B.C., YUKON & N.W.T.

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
CHEVRON CANADA	48.8	60.6	79.0	90.9	98.3
GULF POST-NEP	31.2	36.1	41.6	46.5	51.1
SHELL PRE-NEP	29.4	31.4	33.6	35.9	38.4
TEXACO PRE-NEP	33.5	40.5	47.4	53.5	62.0
NEB MIDDLE DEMAND CASE	53.2	58.7	66.3	74.1	81.7

TOTAL DEMAND FOR

OTHER PETROLEUM PRODUCTS - TOTAL CANADA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
DOME	427.4	499.6	549.6	579.6	613.9
GULF POST-NEP	436.8	590.0	664.9	681.2	713.8
IMPERIAL PRE-NEP	626.0	707.0	772.0	842.0	953.0
IMPERIAL POST-NEP	441.0		589.0		770.0
PETRO-CANADA (MAR.12,1981)	377.1	478.8	530.6	558.9	590.9
SHELL PRE-NEP	445.0	510.6	535.2	563.6	592.9
TEXACO PRE-NEP	462.0	617.0	725.7	781.3	838.0
NEB MIDDLE DEMAND CASE	678.2	757.3	794.8	886.7	1 073.2

TOTAL DEMAND FOR

TOTAL PETROLEUM PRODUCTS - NEWFOUNDLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEWFOUNDLAND	130.0	145.3	125.0	134.5	145.4
SHELL PRE-NEP	125.6	131.8	140.9	153.2	167.8
SHELL POST-NEP		128.1	136.2		160.3
NEB MIDDLE DEMAND CASE	133.1	135.5	107.7	113.5	110.4

TOTAL DEMAND FOR

TOTAL PETROLEUM PRODUCTS - NOVA SCOTIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NOVA SCOTIA PRE-NEP	191.1	146.1	153.3	162.7	172.4
NOVA SCOTIA POST-NEP		135.9	142.3	151.5	160.6
NEB MIDDLE DEMAND CASE	202.7	198.0	156.2	150.2	152.4

TOTAL DEMAND FOR

TOTAL PETROLEUM PRODUCTS - NEW BRUNSWICK

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEW BRUNSWICK		180.9			
NEB MIDDLE DEMAND CASE	185.5	145.0	124.4	137.4	125.7

TOTAL DEMAND FOR

TOTAL PETROLEUM PRODUCTS - PRINCE EDWARD ISLAND

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
NEB MIDDLE DEMAND CASE	19.9	20.0	20.1	20.2	20.1

TOTAL DEMAND FOR

TOTAL PETROLEUM PRODUCTS - ATLANTIC

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	566.1	422.7	385.3	380.8	385.5
IMPERIAL PRE-NEP	526.0	492.0	383.0	346.0	332.0
NOVA	579.0	533.0	505.0	490.0	499.0
PETRO-CANADA (MAR.12,1981)	499.7	437.1	381.2	363.1	354.7
SHELL PRE-NEP	589.8	572.1	592.4	619.5	662.8
SHELL POST-NEP		532.3	532.2		547.5
TEXACO PRE-NEP	577.1	572.1	505.3	498.4	524.2
NEB MIDDLE DEMAND CASE	540.9	497.9	407.3	421.2	408.1

TOTAL DEMAND FOR

TOTAL PETROLEUM PRODUCTS - QUEBEC

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	1 126.4	1 014.4	950.9	936.1	952.2
IMPERIAL	PRE-NEP	1 121.0	990.0	861.0	805.0	759.0
NOVA		1 135.0	1 031.0	941.0	867.0	858.0
PETRO-CANADA	(MAR.12,1981)	1 030.9	912.1	841.5	815.9	832.6
SHELL	PRE-NEP	1 107.4	1 039.1	848.7	837.8	867.7
SHELL	POST-NEP		977.5	776.2		770.1
TEXACO	PRE-NEP	1 123.1	1 004.9	931.5	859.4	850.3
NEB	MIDDLE DEMAND CASE	1 099.7	924.8	802.8	807.2	810.5

TOTAL DEMAND FOR

TOTAL PETROLEUM PRODUCTS - ONTARIO

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	1 313.1	1 215.5	1 189.8	1 216.4	1 281.3
IMPERIAL	PRE-NEP	1 304.0	1 175.0	1 096.0	1 071.0	1 057.0
NOVA		1 352.0	1 282.0	1 339.0	1 330.0	1 392.0
ONTARIO		1 303.0	1 316.0	1 379.0	1 406.0	1 436.0
ONTARIO	POST-NEP				1 163.0	
PETRO-CANADA	(MAR.12,1981)	1 148.9	1 062.6	1 020.0	1 018.1	1 077.3
SHELL	PRE-NEP	1 312.8	1 310.9	1 221.2	1 257.6	1 329.3
SHELL	POST-NEP		1 215.1	1 073.2		1 080.5
TEXACO	PRE-NEP	1 339.0	1 286.7	1 331.1	1 312.4	1 353.0
UNION		1 152.0	1 212.0	1 246.0	1 249.0	1 197.0
NEB	MIDDLE DEMAND CASE	1 260.8	1 196.2	1 141.1	1 145.1	1 203.6

TOTAL DEMAND FOR

TOTAL PETROLEUM PRODUCTS - MANITOBA

COMPARISON OF FORECASTS

(PETAJOULES)

		1980 EST	1985	1990	1995	2000
GULF	POST-NEP	130.4	130.6	133.7	140.4	147.5
MANITOBA	POST-NEP	114.9	101.7	97.6	97.4	102.3
NOVA		125.0	121.0	124.0	124.0	134.0
PETRO-CANADA	(MAR.12,1981)	125.4	115.8	113.9	115.3	124.5
SHELL	PRE-NEP	126.8	129.9	132.3	138.6	147.7
SHELL	POST-NEP		120.4	120.6		128.2
TEXACO	PRE-NEP	124.0	121.1	123.3	123.3	131.8
NEB	MIDDLE DEMAND CASE	120.7	120.9	121.5	122.9	133.4

TOTAL DEMAND FOR

TOTAL PETROLEUM PRODUCTS - SASKATCHEWAN

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	151.8	163.6	176.6	184.0	196.9
NOVA	159.0	154.0	158.0	158.0	166.0
PETRO-CANADA (MAR.12,1981)	151.4	148.9	150.0	154.0	161.2
SHELL PRE-NEP	153.9	163.5	173.5	191.1	206.7
SHELL POST-NEP		158.1	165.3		183.1
TEXACO PRE-NEP	157.1	154.5	157.4	155.4	161.9
NEB MIDDLE DEMAND CASE	153.1	159.3	166.8	173.8	188.6

TOTAL DEMAND FOR

TOTAL PETROLEUM PRODUCTS - ALBERTA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
GULF POST-NEP	369.8	483.3	553.9	615.5	677.3
IMPERIAL PRE-NEP	394.0	524.0	640.0	791.0	930.0
NOVA	352.0	418.0	468.0	498.0	556.0
PETRO-CANADA (MAR.12,1981)	351.3	458.2	538.9	598.4	648.6
SHELL PRE-NEP	403.2	543.7	597.1	634.9	713.4
SHELL POST-NEP		528.9	583.1		706.5
TEXACO PRE-NEP	348.2	422.0	469.1	497.5	551.8
NEB MIDDLE DEMAND CASE	392.9	485.3	563.2	626.6	825.1

TOTAL DEMAND FOR

TOTAL PETROLEUM PRODUCTS - BRITISH COLUMBIA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
B.C.	356.4	438.4	463.3	504.1	
IMPERIAL PRE-NEP	415.0	448.0	480.0	518.0	537.0
NOVA	444.0	428.0	454.0	475.0	524.0
PETRO-CANADA (MAR.12,1981)	374.6	350.7	363.1	388.4	424.6

TOTAL DEMAND FOR

TOTAL PETROLEUM PRODUCTS - B.C., YUKON & N.W.T.

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
CHEVRON CANADA	414.1	482.4	524.1	558.8	587.0
GULF POST-NEP	427.3	424.4	430.2	451.5	486.1
SHELL PRE-NEP	439.1	490.5	523.2	554.5	602.5
SHELL POST-NEP		477.0	495.1		565.1
TEXACO PRE-NEP	439.5	430.2	437.9	440.6	488.8
NEB MIDDLE DEMAND CASE	440.1	445.5	487.4	538.0	608.1

TOTAL DEMAND FOR

TOTAL PETROLEUM PRODUCTS - TOTAL CANADA

COMPARISON OF FORECASTS

(PETAJOULES)

	1980 EST	1985	1990	1995	2000
DOME	3 822.9	3 686.0	3 690.4	3 893.8	4 189.7
GULF POST-NEP	4 085.1	3 853.8	3 820.1	3 922.7	4 126.6
IMPERIAL PRE-NEP	4 074.0	3 956.0	3 791.0	3 871.0	3 960.0
IMPERIAL POST-NEP	4 073.0		3 789.0		3 960.0
NORCEN POST-NEP	4 092.3	3 350.3	3 652.0	3 654.0	3 809.5
NOVA	4 146.0	3 967.0	3 991.0	3 942.0	4 129.0
PETRO-CANADA (MAR.12,1981)	3 682.4	3 485.1	3 407.3	3 453.2	3 624.0
SHELL PRE-NEP	4 133.4	4 250.2	4 088.9	4 234.6	4 530.5
SHELL POST-NEP		4 013.1	3 748.7		3 955.6
TEXACO PRE-NEP	4 095.7	3 987.9	3 955.0	3 876.3	4 066.4
TEXACO POST-NEP		3 894.0	3 808.0	3 708.0	3 858.0
NEB MIDDLE DEMAND CASE	4 007.8	3 830.3	3 690.9	3 835.1	4 177.7

1980

DEMAND FOR REFINERY FEEDSTOCKS
(Crude Oil & Equivalent)
($10^3m^3/d$)

	Gulf	Shell	Imperial	Texaco	NEB Actual Demand
Québec and East					
Total Domestic Sales of Refined Petroleum Product	113	114	111	111	110
Add Sales of Refinery Produced LPGs	2	2	2	3	1
Deduct Product Imports	(2)	(5)	(1)	(2)	(5)
Add Product Exports	8	—	2	15	10
Net Product Transfers Out/(In)	4	7	3	5	2
Losses, Industry Use and Other Adjustments	8	8	7	9	4
Deduct Gas Plant Butanes Supplied to Refineries	—	—	—	(1)	—
Total Feedstocks Demand	133	126	124	140	123
Ontario and West					
Total Domestic Sales of Refined Petroleum Product	166	169	167	160	165
Add Sales of Refinery Produced LPGs	4	2	4	4	4
Deduct Product Imports	(1)	(2)	(4)	(4)	(2)
Add Product Exports	8	6	7	5	10
Net Product Transfers Out/(In)	(4)	(7)	(3)	(5)	(2)
Losses, Industry Use and Other Adjustments	10	14	10	10	6
Deduct Gas Plant Butanes Supplied to Refineries	(3)	(3)	(3)	(1)	(2)
Total Feedstocks Demand	180	180	178	169	178
Canada					
Total Domestic Sales of Refined Petroleum Product	279	283	278	271	275
Add Sales of Refinery Produced LPGs	6	4	6	7	5
Deduct Product Imports	(3)	(6)	(5)	(6)	(7)
Add Product Exports	16	6	9	20	20
Losses, Industry Use and Other Adjustments	18	22	17	19	10
Deduct Gas Plant Butanes Supplied to Refineries	(3)	(3)	(3)	(2)	(2)
Total Feedstocks Demand	313	306	302	309	301

1981

DEMAND FOR REFINERY FEEDSTOCKS
(Crude Oil & Equivalent)
($10^3m^3/d$)

	Gulf	Shell	Imperial	Texaco	NEB Middle Demand Case
Québec and East					
Total Domestic Sales of Refined Petroleum Product	110	113	109	110	105
Add Sales of Refinery Produced LPGs	2	1	2	3	2
Deduct Product Imports	—	(2)	(1)	(3)	(2)
Add Product Exports	—	—	4	12	1
Net Product Transfers Out/(In)	5	8	3	5	2
Losses, Industry Use and Other Adjustments	8	7	7	9	8
Deduct Gas Plant Butanes Supplied to Refineries	—	—	—	(1)	—
Total Feedstocks Demand	125	127	124	135	115
Ontario and West					
Total Domestic Sales of Refined Petroleum Product	166	172	169	158	163
Add Sales of Refinery Produced LPGs	4	3	4	4	4
Deduct Product Imports	—	(2)	(4)	(4)	(1)
Add Product Exports	7	5	8	5	5
Net Product Transfers Out/(In)	(5)	(8)	(3)	(5)	(2)
Losses, Industry Use and Other Adjustments	10	16	9	10	9
Deduct Gas Plant Butanes Supplied to Refineries	(2)	(3)	(3)	(1)	(2)
Total Feedstocks Demand	180	183	180	167	177
Canada					
Total Domestic Sales of Refined Petroleum Product	276	285	278	268	268
Add Sales of Refinery Produced LPGs	6	4	6	7	6
Deduct Product Imports	—	(4)	(5)	(7)	(3)
Add Product Exports	7	5	12	17	6
Losses, Industry Use and Other Adjustments	18	23	16	19	17
Deduct Gas Plant Butanes Supplied to Refineries	(2)	(3)	(3)	(2)	(2)
Total Feedstocks Demand	305	310	304	302	292

1982

DEMAND FOR REFINERY FEEDSTOCKS
(Crude Oil & Equivalent)
($10^3m^3/d$)

	Gulf	Shell	Imperial	Texaco	NEB Middle Demand Case
Québec and East					
Total Domestic Sales of Refined Petroleum Product	107	111	106	109	103
Add Sales of Refinery Produced LPGs	2	2	2	3	2
Deduct Product Imports	—	(1)	(2)	(4)	(1)
Add Product Exports	—	—	6	11	2
Net Product Transfers Out/(In)	5	9	3	5	2
Losses, Industry Use and Other Adjustments	8	8	7	9	7
Deduct Gas Plant Butanes Supplied to Refineries	—	—	—	(1)	—
Total Feedstocks Demand	122	128	122	131	115
Ontario and West					
Total Domestic Sales of Refined Petroleum Product	166	175	170	157	164
Add Sales of Refinery Produced LPGs	4	2	4	4	4
Deduct Product Imports	—	(2)	(4)	(4)	(2)
Add Product Exports	7	5	11	5	6
Net Product Transfers Out/(In)	(5)	(9)	(3)	(5)	(2)
Losses, Industry Use and Other Adjustments	10	16	9	10	9
Deduct Gas Plant Butanes Supplied to Refineries	(2)	(3)	(3)	(1)	(2)
Total Feedstocks Demand	180	184	184	166	178
Canada					
Total Domestic Sales of Refined Petroleum Product	273	286	276	265	267
Add Sales of Refinery Produced LPGs	6	4	6	7	6
Deduct Product Imports	—	(3)	(6)	(8)	(3)
Add Product Exports	7	5	17	16	8
Losses, Industry Use and Other Adjustments	18	23	16	19	17
Deduct Gas Plant Butanes Supplied to Refineries	(2)	(3)	(3)	(2)	(2)
Total Feedstocks Demand	302	312	306	297	293

1983

DEMAND FOR REFINERY FEEDSTOCKS
(Crude Oil & Equivalent)
($10^3m^3/d$)

	Gulf	Shell	Imperial	Texaco	NEB Middle Demand Case
Québec and East					
Total Domestic Sales of Refined Petroleum Product	103	110	104	108	101
Add Sales of Refinery Produced LPGs	2	2	2	3	2
Deduct Product Imports	—	(1)	(2)	(5)	(1)
Add Product Exports	—	1	8	9	4
Net Product Transfers Out/(In)	5	10	3	5	2
Losses, Industry Use and Other Adjustments	8	7	7	8	7
Deduct Gas Plant Butanes Supplied to Refineries	—	—	—	(1)	—
Total Feedstocks Demand	118	129	122	126	115
Ontario and West					
Total Domestic Sales of Refined Petroleum Product	164	177	170	156	163
Add Sales of Refinery Produced LPGs	4	2	4	4	4
Deduct Product Imports	—	(2)	(4)	(4)	(1)
Add Product Exports	5	4	10	5	5
Net Product Transfers Out/(In)	(5)	(10)	(3)	(5)	(2)
Losses, Industry Use and Other Adjustments	10	16	9	10	9
Deduct Gas Plant Butanes Supplied to Refineries	(2)	(3)	(3)	(1)	(2)
Total Feedstocks Demand	176	184	183	165	176
Canada					
Total Domestic Sales of Refined Petroleum Product	268	287	274	263	264
Add Sales of Refinery Produced LPGs	6	4	6	7	6
Deduct Product Imports	—	(3)	(6)	(9)	(2)
Add Product Exports	5	5	18	14	9
Losses, Industry Use and Other Adjustments	18	23	16	18	16
Deduct Gas Plant Butanes Supplied to Refineries	(2)	(3)	(3)	(2)	(2)
Total Feedstocks Demand	294	313	305	291	291

1984

DEMAND FOR REFINERY FEEDSTOCKS
(Crude Oil & Equivalent)
($10^3 m^3/d$)

	Gulf	Shell	Imperial	Texaco	NEB Middle Demand Case
Québec and East					
Total Domestic Sales of Refined Petroleum Product	101	109	102	108	99
Add Sales of Refinery Produced LPGs	2	2	3	3	2
Deduct Product Imports	—	(1)	(2)	(6)	(2)
Add Product Exports	—	3	7	7	6
Net Product Transfers Out/(In)	5	10	3	5	1
Losses, Industry Use and Other Adjustments	8	7	6	8	7
Deduct Gas Plant Butanes Supplied to Refineries	—	—	—	(1)	—
Total Feedstocks Demand	115	130	119	125	113
Ontario and West					
Total Domestic Sales of Refined Petroleum Product	164	181	170	155	163
Add Sales of Refinery Produced LPGs	4	3	4	4	5
Deduct Product Imports	—	(2)	(4)	(4)	(1)
Add Product Exports	5	4	7	5	5
Net Product Transfers Out/(In)	(5)	(10)	(3)	(5)	(1)
Losses, Industry Use and Other Adjustments	10	14	10	10	9
Deduct Gas Plant Butanes Supplied to Refineries	(2)	(3)	(3)	(1)	(2)
Total Feedstocks Demand	176	187	181	164	178
Canada					
Total Domestic Sales of Refined Petroleum Product	265	290	272	263	262
Add Sales of Refinery Produced LPGs	6	5	7	7	7
Deduct Product Imports	—	(3)	(6)	(10)	(3)
Add Product Exports	5	7	14	13	11
Losses, Industry Use and Other Adjustments	18	21	16	18	16
Deduct Gas Plant Butanes Supplied to Refineries	(2)	(3)	(3)	(2)	(2)
Total Feedstocks Demand	291	317	300	289	291

1985

DEMAND FOR REFINERY FEEDSTOCKS
(Crude Oil & Equivalent)
($10^3m^3/d$)

	Gulf	Shell	Imperial	Texaco	NEB Middle Demand Case
Québec and East					
Total Domestic Sales of Refined Petroleum Product	97	109	99	103	95
Add Sales of Refinery Produced LPGs	2	2	3	3	2
Deduct Product Imports	—	(1)	(2)	(7)	(2)
Add Product Exports	—	2	5	4	8
Net Product Transfers Out/(In)	5	13	35	—	
Losses, Industry Use and Other Adjustments	7	7	6	8	7
Deduct Gas Plant Butanes Supplied to Refineries	—	—	—	(1)	—
Total Feedstocks Demand	111	132	114	119	110
Ontario and West					
Total Domestic Sales of Refined Petroleum Product	167	182	172	161	166
Add Sales of Refinery Produced LPGs	4	3	4	4	4
Deduct Product Imports	—	(2)	(4)	(4)	(1)
Add Product Exports	—	—	8	5	1
Net Product Transfers Out/(In)	(5)	(13)	(3)	(5)	—
Losses, Industry Use and Other Adjustments	10	16	10	10	9
Deduct Gas Plant Butanes Supplied to Refineries	(2)	(3)	(4)	(1)	(2)
Total Feedstocks Demand	174	183	183	170	177
Canada					
Total Domestic Sales of Refined Petroleum Product	264	291	271	264	261
Add Sales of Refinery Produced LPGs	6	5	7	7	6
Deduct Product Imports	—	(3)	(6)	(11)	(3)
Add Product Exports	—	2	13	11	9
Losses, Industry Use and Other Adjustments	17	23	16	18	16
Deduct Gas Plant Butanes Supplied to Refineries	(2)	(3)	(4)	(2)	(2)
Total Feedstocks Demand	285	315*	297	289	287

*Amended to 296 in supplementary submission

1990

DEMAND FOR REFINERY FEEDSTOCKS
(Crude Oil & Equivalent)
($10^3m^3/d$)

	Gulf	Shell	Imperial	Texaco	NEB Middle Demand Case
Québec and East					
Total Domestic Sales of Refined Petroleum Product	91	100	84	94	82
Add Sales of Refinery Produced LPGs	2	2	2	3	2
Deduct Product Imports	—	(1)	(2)	(9)	—
Add Product Exports	—	1	11	—	
Net Product Transfers Out/(In)	5	10	35	—	
Losses, Industry Use and Other Adjustments	7	2	6	8	5
Deduct Gas Plant Butanes Supplied to Refineries	—	—	—	(1)	—
Total Feedstocks Demand	105	114	94	100	89
Ontario and West					
Total Domestic Sales of Refined Petroleum Product	171	184	177	168	170
Add Sales of Refinery Produced LPGs	4	3	4	5	5
Deduct Product Imports	—	(3)	(5)	(5)	(1)
Add Product Exports	—	1	2	3	1
Net Product Transfers Out/(In)	(5)	(10)	(3)	(5)	—
Losses, Industry Use and Other Adjustments	9	14	9	10	9
Deduct Gas Plant Butanes Supplied to Refineries	(2)	(3)	(4)	(1)	(2)
Total Feedstocks Demand	177	186	180	175	182
Canada					
Total Domestic Sales of Refined Petroleum Product	262	284	261	262	252
Add Sales of Refinery Produced LPGs	6	5	6	8	7
Deduct Product Imports	—	(4)	(7)	(14)	(1)
Add Product Exports	—	2	3	4	1
Losses, Industry Use and Other Adjustments	16	16	15	18	14
Deduct Gas Plant Butanes Supplied to Refineries	(2)	(3)	(4)	(3)	(2)
Total Feedstocks Demand	282	300*	274	275	271

*Amended to 273 in supplementary submission

1995

DEMAND FOR REFINERY FEEDSTOCKS
(Crude Oil & Equivalent)
($10^3m^3/d$)

	Gulf	Shell	Imperial	Texaco	NEB Middle Demand Case
Québec and East					
Total Domestic Sales of Refined Petroleum Product	90	102	80	89	83
Add Sales of Refinery Produced LPGs	2	2	2	3	2
Deduct Product Imports	—	(1)	(2)	(12)	—
Add Product Exports	—	2	—	1	—
Net Product Transfers Out/(In)	6	10	3	5	—
Losses, Industry Use and Other Adjustments	6	3	5	7	5
Deduct Gas Plant Butanes Supplied to Refineries	—	—	—	(1)	—
Total Feedstocks Demand	104	118	88	91	90
Ontario and West					
Total Domestic Sales of Refined Petroleum Product	180	193	187	169	179
Add Sales of Refinery Produced LPGs	4	3	4	5	5
Deduct Product Imports	—	(4)	(6)	(6)	(1)
Add Product Exports	—	5	—	3	—
Net Product Transfers Out/(In)	(6)	(10)	(3)	(5)	—
Losses, Industry Use and Other Adjustments	10	14	10	10	10
Deduct Gas Plant Butanes Supplied to Refineries	(2)	(3)	(4)	(1)	(2)
Total Feedstocks Demand	186	198	188	175	191
Canada					
Total Domestic Sales of Refined Petroleum Product	270	294	267	258	262
Add Sales of Refinery Produced LPGs	6	5	6	8	7
Deduct Product Imports	—	(5)	(8)	(18)	(1)
Add Product Exports	—	8	—	4	—
Losses, Industry Use and Other Adjustments	16	17	15	17	15
Deduct Gas Plant Butanes Supplied to Refineries	(2)	(3)	(4)	(3)	(2)
Total Feedstocks Demand	290	316	276	266	281

2000

DEMAND FOR REFINERY FEEDSTOCKS
(Crude Oil & Equivalent)
($10^3 m^3/d$)

	Gulf	Shell	Imperial	Texaco	NEB Middle Demand Case
Québec and East					
Total Domestic Sales of Refined Petroleum Product	92	107	76	90	82
Add Sales of Refinery Produced LPGs	2	2	2	4	2
Deduct Product Imports	—	(1)	(2)	(15)	—
Add Product Exports	—	4	—	1	—
Net Product Transfers Out/(In)	6	11	3	5	(1)
Losses, Industry Use and Other Adjustments	6	4	5	7	6
Deduct Gas Plant Butanes Supplied to Refineries	—	—	—	(1)	—
Total Feedstocks Demand	106	127	84	90	89
Ontario and West					
Total Domestic Sales of Refined Petroleum Product	193	208	196	180	203
Add Sales of Refinery Produced LPGs	4	3	5	5	5
Deduct Product Imports	—	(3)	(6)	(7)	—
Add Product Exports	—	12	—	3	—
Net Product Transfers Out/(In)	(6)	(11)	(3)	(5)	1
Losses, Industry Use and Other Adjustments	10	14	10	11	10
Deduct Gas Plant Butanes Supplied to Refineries	(2)	(3)	(4)	(1)	(2)
Total Feedstocks Demand	199	220	198	186	217
Canada					
Total Domestic Sales of Refined Petroleum Product	285	315	272	270	285
Add Sales of Refinery Produced LPGs	6	5	7	9	7
Deduct Product Imports	—	(4)	(8)	(22)	—
Add Product Exports	—	16	—	4	—
Losses, Industry Use and Other Adjustments	16	18	15	18	16
Deduct Gas Plant Butanes Supplied to Refineries	(2)	(3)	(4)	(3)	(2)
Total Feedstocks Demand	305	347*	282	276	306

*Amended to 301 in supplementary submission

CRUDE OILS INCLUDED IN NEB HEAVY CRUDE OIL CATEGORY

- Lloydminster-type blended crude oil delivered to the Interprovincial pipeline system either at Hardisty, Alberta or at Kerrobert, Saskatchewan.
- Wainwright and Viking-Kinsella blended crude oils delivered to the Interprovincial pipeline system at Hardisty, Alberta.
- Chauvin crude oil delivered to the Interprovincial pipeline system through the BP Exploration Canada Limited Chauvin-Hardisty pipeline system.
- Area III medium crude oil in Saskatchewan (Fosterton).
- The Bow River Pipelines Ltd. stream in Alberta, excluding light and medium crude oil normally batched separately.
- Area II blended heavy crude oil in Saskatchewan excluding light crude oil normally batched separately (Smiley-Coleville).
- Area IV medium crude oil in Saskatchewan (Midale-Weyburn).
- Other crude oil with API gravity less than 25° API.

CONVENTIONAL CRUDE OIL - ESTABLISHED RESERVES AND PRODUCTIVE CAPACITY - NEB ESTIMATES

LIGHT CRUDE OIL

	INITIAL RECOVERABLE RESERVES	CUMULATIVE PRODUCTION TO 1/1/80	REMAINING RESERVES AT 1/1/80	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000
	(MILLION CUBIC METRES)			(CUBIC METRES PER DAY)												
NORTHWEST TERRITORIES																
NORMAN WELLS																
NORMAN WELLS	9.5	3.8	5.7	477	477	477	477	477	477	477	477	477	477	477	477	477
NORTHWEST TERRITORIES TOTAL	9.5	3.8	5.7	477	477	477	477	477	477	477	477	477	477	477	477	477
BRITISH COLUMBIA																
BLUEBERRY - TAYLOR PIPELINES																
AITKEN CREEK-GETHING	.9	.9	.1	26	24	22	20	19	17	12	0	0	0	0	0	0
BLUEBERRY - DEBOLT	2.0	1.8	.2	121	90	67	50	37	28	21	7	0	0	0	0	0
EAGLE - BELLOY (55%)	5.5	.3	5.2	614	742	870	935	935	935	901	816	739	668	605	367	222
INGA - INGA	6.2	4.4	1.9	517	474	431	390	353	319	288	261	236	213	193	116	70
STODDART WEST	.7	.1	.7	147	143	135	124	113	104	95	88	80	74	68	44	28
OTHER	.4	.2	.2	53	49	44	40	36	33	29	27	24	22	20	12	7
PIPELINE TOTAL	15.9	7.7	8.1	1480	1524	1572	1561	1495	1437	1350	1200	1080	978	886	540	329
TRANS-PRAIRIE PIPELINE LTD.: BEATTON RIVER - TAYLOR																
BEATTON RIVER - HALFWAY	1.5	1.2	.3	109	97	87	78	69	62	56	50	44	40	36	20	0
BEATTON RIVER WEST - BLUESKY GETHING	.7	.6	.2	83	71	60	51	43	37	31	26	22	19	16	0	0
EAGLE - BELLOY (45%)	4.5	.3	4.3	502	607	712	765	765	765	737	668	604	547	495	300	182
MILLIGAN CREEK - HALFWAY	6.4	6.1	.4	199	177	150	122	99	80	65	53	39	0	0	0	0
PEEJAY - HALFWAY	9.0	8.4	.6	386	322	251	196	153	119	93	73	57	9	0	0	0
WEASEL - HALFWAY	2.8	2.2	.6	277	242	203	170	142	119	100	84	70	59	49	0	0
WILDMINT - HALFWAY	1.3	1.2	.1	71	56	45	36	28	22	18	14	11	9	0	0	0
OTHER	1.5	1.3	.2	139	116	92	73	58	46	37	4	0	0	0	0	0
PIPELINE TOTAL	27.8	21.2	6.6	1770	1691	1603	1493	1361	1254	1140	974	850	684	597	321	182
TRANS-PRAIRIE PIPELINES LTD.: BOUNDARY LAKE - TAYLOR																
BOUNDARY LAKE UNIT NO.1	18.6	10.4	8.2	1258	1179	1112	1055	1002	951	903	857	813	772	733	565	435
BOUNDARY LAKE UNIT NO.2	11.8	8.0	3.8	877	835	780	716	657	603	553	508	466	427	392	255	166
OTHER	3.4	2.6	.8	214	198	179	161	145	131	118	106	96	86	78	46	27
PIPELINE TOTAL	33.7	21.0	12.7	2351	2213	2071	1933	1805	1685	1575	1472	1376	1287	1204	867	629

CONVENTIONAL CRUDE OIL - ESTABLISHED RESERVES AND PRODUCTIVE CAPACITY - NEB ESTIMATES

LIGHT CRUDE OIL

	INITIAL RECOVERABLE RESERVES	CUMULATIVE PRODUCTION TO 1/1/80	REMAINING RESERVES AT 1/1/80	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000
	(MILLION CUBIC METRES)			(CUBIC METRES PER DAY)												
BRITISH COLUMBIA TRUCKED OIL																
TRUCKED OIL - TOTAL	1.9	.5	1.4	204	196	185	175	166	157	149	141	133	126	119	90	68
BRITISH COLUMBIA TOTAL	79.3	50.4	28.9	5807	5625	5434	5164	4828	4535	4214	3788	3441	3076	2807	1819	1210
ALBERTA																
BOW RIVER PIPE LINES LTD.: LIGHT & MEDIUM																
PROVOST - VIKING CAK	9.2	5.3	3.9	1048	953	865	786	714	649	590	536	487	442	402	248	154
OTHER	1.1	.4	.8	178	174	165	150	136	124	113	102	93	85	77	48	30
PIPELINE TOTAL	10.3	5.6	4.7	1227	1127	1030	936	851	773	703	639	580	527	479	297	184
CREMONA PIPELINE																
CROSSFIELD - CARDIUM A	2.9	2.6	.3	109	98	88	79	71	64	58	52	47	42	38	0	0
HARMATTEN EAST - RUNDLE	11.6	8.5	3.2	1167	1017	887	773	673	587	512	446	388	339	295	148	74
HARMATTEN ELKTON - RUNDLE C	9.9	7.1	2.9	894	819	728	647	575	511	454	403	358	319	283	157	87
OTHER	5.6	4.2	1.4	386	360	333	305	280	257	235	216	198	182	167	108	0
PIPELINE TOTAL	30.1	22.4	7.7	2558	2295	2037	1805	1601	1420	1260	1119	993	882	784	414	162
FEDERATED PIPE LINES LTD.																
CARSON CREEK NORTH - BHL A	5.8	3.4	2.4	1067	1005	882	719	586	477	389	317	258	210	171	61	0
CARSON CREEK NORTH - BHL B	16.2	10.9	5.3	2199	2010	1758	1468	1227	1025	856	715	597	499	417	169	0
JUDY CREEK - BHL A	54.0	37.2	16.8	5611	4636	3891	3309	2847	2474	2169	1916	1704	1525	1372	865	592
JUDY CREEK - BHL B	18.5	12.1	6.4	2202	1861	1588	1366	1185	1034	908	802	712	635	569	347	228
MEEKWAP - D-2A	4.2	1.6	2.5	607	583	546	498	453	413	377	343	313	285	260	163	102
SWAN HILLS - BHL A&B	105.0	68.0	37.0	9176	8378	7649	6983	6376	5821	5315	4853	4431	4045	3693	2343	1486
SWAN HILLS - BHL C	23.8	14.3	9.5	1930	1797	1674	1559	1452	1352	1259	1173	1092	1017	947	664	465
SWAN HILLS SOUTH - BHL A&B	66.0	40.1	25.9	8415	7691	6904	6083	5360	4723	4161	3667	3231	2847	2508	1332	707
VIRGINIA HILLS - BHL	20.7	16.4	4.2	1950	1733	1434	1186	982	812	672	556	460	381	315	122	0
OTHER	2.1	.8	1.2	360	324	291	262	236	212	191	171	154	139	125	73	43
PIPELINE TOTAL	316.3	204.9	111.4	33522	30022	26621	23439	20707	18348	16301	14517	12956	11587	10381	6144	3627

CONVENTIONAL CRUDE OIL - ESTABLISHED RESERVES AND PRODUCTIVE CAPACITY - NEB ESTIMATES

LIGHT CRUDE OIL

	INITIAL RECOVERABLE RESERVES	CUMULATIVE PRODUCTION TO 1/1/80	REMAINING RESERVES AT 1/1/80	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000
	(MILLION CUBIC METRES)			(CUBIC METRES PER DAY)												
GIBSON PETROLEUM COMPANY LIMITED																
BELLSHILL LAKE - BLAIRMORE	9.1	5.2	4.0	916	872	829	774	709	649	594	544	499	457	418	269	173
THOMPSON LAKE - BLAIRMORE	.7	.5	.2	66	62	56	51	46	42	38	34	31	28	25	15	1
PIPELINE TOTAL	9.8	5.6	4.2	983	934	886	825	755	691	633	579	530	485	444	285	174
GULF ALBERTA PIPE LINE																
CLIVE - D-2A	3.1	1.5	1.6	360	324	293	266	242	221	203	187	172	159	147	104	76
CLIVE - D-3A	6.9	3.4	3.5	795	740	680	625	575	528	486	447	410	377	347	227	149
DRUMHELLER - D-2B	1.6	.8	.8	192	187	177	161	147	134	123	112	102	93	85	54	34
DUHAMEL - D-2A	1.0	.9	.1	54	45	37	30	25	21	17	3	0	0	0	0	0
DUHAMEL - D-3B	1.2	1.0	.3	93	91	83	71	61	52	44	38	32	28	24	0	0
ERSKINE - D-3	3.7	3.2	.5	152	137	124	112	101	92	83	75	68	61	55	33	0
FENN BIG VALLEY - D-2A	42.0	30.0	12.0	7803	7422	5964	3995	2676	1793	1201	804	539	361	241	0	0
HUSSAR - GLAUCONITIC A	3.3	2.2	1.1	370	338	297	260	228	200	175	154	135	118	104	54	0
JOFFRE - D-2	9.0	5.8	3.2	470	433	401	373	347	325	304	286	269	254	240	186	149
STETTLER - D-2A	4.0	3.6	.4	171	150	127	107	91	77	65	55	47	40	33	0	0
STETTLER - D-3A	3.7	2.5	1.2	346	324	290	260	232	208	186	166	149	133	119	68	39
WEST DRUMHELLER - D-2A	4.7	3.8	.9	294	264	237	213	192	173	155	140	125	113	101	59	0
OTHER	28.6	19.9	8.7	2178	2135	2009	1814	1637	1478	1335	1205	1088	982	887	532	319
PIPELINE TOTAL	112.7	78.5	34.2	13283	12596	10725	8294	6562	5307	4383	3677	3141	2724	2389	1320	768
THE IMPERIAL PIPE LINE COMPANY, LIMITED: ELLERSLIE																
ACHESON - D-3A	17.5	12.8	4.7	2265	2198	1915	1489	1158	900	700	544	423	329	256	72	0
GOLDEN SPIKE - D-3A	29.5	26.4	3.1	1061	881	783	696	619	550	489	434	386	343	305	169	93
ST. ALBERT - D-3A	2.6	1.9	.7	301	260	224	193	166	143	123	106	91	79	68	32	0
OTHER	7.2	4.8	2.4	703	635	573	517	467	422	381	344	310	280	253	152	91
PIPELINE TOTAL	56.8	45.9	10.9	4333	3975	3496	2896	2411	2016	1694	1430	1212	1032	882	426	185
THE IMPERIAL PIPE LINE COMPANY, LIMITED: EXCELSIOR																
EXCELSIOR D-2	4.5	3.5	1.0	580	486	375	290	224	173	133	103	79	61	47	0	0
FAIRYDELL-BON ACCORD - D-3A	1.8	1.4	.4	170	153	129	108	91	77	65	54	46	39	32	0	0
OTHER	.7	.6	.1	59	50	42	36	30	25	21	18	15	13	11	0	0
PIPELINE TOTAL	7.1	5.6	1.5	811	690	547	435	346	276	221	176	141	114	91	0	0

CONVENTIONAL CRUDE OIL - ESTABLISHED RESERVES AND PRODUCTIVE CAPACITY - NEB ESTIMATES

LIGHT CRUDE OIL

	INITIAL RECOVERABLE RESERVES	CUMULATIVE PRODUCTION TO 1/1/80	REMAINING RESERVES AT 1/1/80	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000
	(MILLION CUBIC METRES)			(CUBIC METRES PER DAY)												
THE IMPERIAL PIPE LINE COMPANY, LIMITED: LEDUC																
LEDUC WOODBEND - D-2A	14.4	13.8	.6	180	171	159	145	132	120	109	99	90	82	74	46	0
LEDUC WOODBEND - D-3A	39.0	36.5	2.6	1160	987	830	698	587	494	415	349	294	247	208	87	0
LEDUC WOODBEND - D-3F	.7	.4	.4	198	161	130	106	86	69	56	46	37	30	24	0	0
OTHER	6.0	5.8	.2	66	61	55	50	46	42	38	35	32	29	26	17	10
PIPELINE TOTAL	60.2	56.4	3.8	1606	1381	1177	1001	852	726	620	530	454	389	334	150	10
THE IMPERIAL PIPE LINE COMPANY, LIMITED : REDWATER																
REDWATER - TOTAL	126.9	109.2	17.7	13022	9183	6855	5117	3820	2851	2128	1589	1186	885	661	0	0
PIPELINE TOTAL	126.9	109.2	17.7	13022	9183	6855	5117	3820	2851	2128	1589	1186	885	661	0	0
MURPHY MILK RIVER PIPE LINE																
COUTTS - TOTAL	.6	.3	.3	114	101	88	76	66	58	50	43	38	33	28	14	0
MANYBERRIES - TOTAL	.9	.3	.6	108	103	96	90	84	78	73	68	64	60	56	39	28
OTHER	1.6	1.3	.3	85	77	69	63	57	51	46	42	38	34	31	18	11
PIPELINE TOTAL	3.1	1.9	1.2	308	281	254	230	208	188	170	154	140	127	116	73	39
NORCEN ENERGY RESOURCES LTD.																
JOARCAM - VIKING	16.5	13.6	2.9	719	662	609	560	516	474	437	402	370	340	313	206	136
PIPELINE TOTAL	16.5	13.6	2.9	719	662	609	560	516	474	437	402	370	340	313	206	136
PEACE RIVER OIL PIPE LINE CO. LTD.																
ANTE CREEK - BHL	3.0	1.3	1.7	206	198	191	184	177	170	164	158	152	146	141	117	97
CHERHILL - BANFF A	3.2	.9	2.3	237	232	226	219	211	204	197	191	184	178	172	145	122
GOOSE RIVER - BHL	7.2	3.9	3.2	803	752	686	626	571	521	476	434	396	361	330	208	132
KAYBOB - BHL A	16.3	12.0	4.3	2091	1846	1514	1242	1019	836	685	562	461	378	310	0	0
KAYBOB SOUTH - TRIASSIC A	13.9	7.1	6.8	1844	1704	1545	1401	1271	1152	1045	948	859	779	707	433	266
NIPISI - GILWOOD A (52%)	23.4	13.2	10.2	2719	2364	2069	1822	1613	1435	1283	1152	1038	939	852	548	374
RED EARTH - GRANITE WASH A	4.0	2.1	1.9	411	377	347	319	294	271	251	232	215	199	185	129	93
SIMONETTE - D-3	5.4	4.8	.6	490	359	263	193	141	103	76	54	0	0	0	0	0
SNIPE LAKE - BHL	11.5	6.6	4.9	778	746	708	671	636	603	572	542	514	488	463	355	272
STURGEON LAKE - D-3	3.4	2.7	.7	280	244	213	186	162	142	124	108	94	82	71	7	0
STURGEON LAKE SOUTH - D-3	24.9	14.8	10.1	2364	2294	2226	2160	2019	1815	1632	1467	1319	1186	1066	626	367
UTIKUMA - KEG RIVER SAND A (16%)	1.0	.4	.6	153	140	129	118	108	100	91	84	77	71	65	42	27
OTHER	13.9	6.4	7.5	1726	1587	1460	1342	1234	1135	1043	960	882	811	746	490	322
PIPELINE TOTAL	131.2	76.4	54.8	14107	12851	11583	10490	9463	8494	7645	6897	6197	5624	5112	3105	2076

CONVENTIONAL CRUDE OIL - ESTABLISHED RESERVES AND PRODUCTIVE CAPACITY - NEB ESTIMATES

LIGHT CRUDE OIL

	INITIAL RECOVERABLE RESERVES	CUMULATIVE PRODUCTION TO 1/1/80	REMAINING RESERVES AT 1/1/80	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000
	(MILLION CUBIC METRES)			(CUBIC METRES PER DAY)												
PEMBINA PIPE LINE LTD.																
BIGORAY - NISKU B	.4	.0	.4	113	106	94	83	74	65	58	51	45	40	36	19	10
BRAZEAU RIVER - NISKU A	4.0	.3	3.7	550	778	718	661	609	561	517	476	439	404	372	247	164
PEMBINA - CARDIUM	228.0	142.6	85.4	8912	8375	7888	7445	7040	6669	6329	6015	5726	5458	5210	4202	3474
PEMBINA - KEYSTONE BELLY RIVER B	9.0	4.4	4.6	913	826	759	708	661	617	576	538	502	468	437	310	219
PEMBINA - NISKU D	2.5	.2	2.3	415	407	399	391	373	346	321	297	276	256	237	162	111
WILLESDEN GREEN - CARDIUM A (70%)	21.0	8.7	12.3	1448	1405	1355	1297	1243	1190	1140	1092	1046	1002	960	774	624
OTHER I	19.8	8.2	11.6	2079	2037	1950	1821	1701	1588	1483	1386	1294	1209	1129	802	570
OTHER II - NISKU	21.6	1.5	20.1	3000	4200	4800	4800	4800	4800	4686	3999	3340	2790	2330	947	385
PIPELINE TOTAL	306.4	165.9	140.4	17433	18138	17965	17210	16503	15840	15113	13857	12671	11630	10714	7466	5560
RAINBOW PIPE LINE COMPANY, LTD.																
MITSUE - GILWOOD A	54.2	28.6	25.6	7022	6680	6354	5836	5170	4580	4057	3594	3184	2821	2499	1363	744
NIPISI - GILWOOD A (48%)	21.6	12.2	9.4	2509	2182	1910	1682	1489	1325	1184	1063	958	866	786	506	345
RAINBOW - KEG RIVER A	11.3	6.0	5.3	1355	1289	1194	1075	968	872	786	708	637	574	517	306	182
RAINBOW - KEG RIVER B	25.6	14.0	11.5	2395	2223	2055	1900	1757	1624	1501	1388	1283	1186	1096	740	500
I.S. NO. 1 - OTHER	12.9	6.6	6.3	1902	1809	1654	1452	1275	1120	983	863	758	666	584	305	159
RAINBOW - KEG RIVER F	17.8	9.8	8.0	2821	2765	2525	2143	1819	1544	1311	1112	944	801	680	299	132
RAINBOW - KEG RIVER I	3.3	1.6	1.7	460	442	410	368	329	295	264	236	212	190	170	98	56
RAINBOW - KEG RIVER AA	12.4	5.3	7.2	1039	1018	998	961	907	857	809	764	721	681	643	483	363
I.S. NO. 11 - OTHER	2.9	2.3	.6	282	243	204	171	143	120	101	84	71	59	50	20	0
I.S. NO. 2 - TOTAL	4.4	2.1	2.3	686	659	607	535	472	416	366	323	285	251	221	118	63
RAINBOW - OTHER	10.6	6.0	4.6	980	941	887	820	758	701	648	599	554	512	474	320	216
RAINBOW SOUTH - KEG RIVER A	2.4	1.5	.9	181	166	154	145	137	130	122	116	109	103	97	73	55
RAINBOW SOUTH - KEG RIVER B	5.0	2.3	2.7	487	460	431	404	379	356	333	313	293	275	258	187	135
RAINBOW SOUTH - KEG RIVER E	3.7	1.7	2.0	394	382	363	337	314	291	271	252	234	218	202	140	97
UTIKUMA - KEG RIVER A (84%)	5.5	2.1	3.4	805	739	678	623	571	525	482	442	406	373	342	223	145
VIRGO - TOTAL	5.7	4.7	1.0	548	527	448	335	250	187	140	104	78	58	35	0	0
ZAMA - TOTAL	11.5	9.3	2.2	1110	1035	905	741	606	496	406	332	272	189	0	0	0
OTHER	14.6	4.9	9.7	1576	1529	1461	1375	1293	1216	1144	1076	1012	952	896	660	486
PIPELINE TOTAL	225.3	120.8	104.5	26561	25099	23248	20911	18647	16662	14917	13379	12020	10783	9559	5848	3683
RANGELAND PIPELINE COMPANY LIMITED																
FERRIER - CARDIUM D	2.0	1.0	.9	277	260	233	209	188	168	151	136	122	109	98	57	33
FERRIER - CARDIUM E	4.8	1.3	3.6	597	591	585	562	523	488	454	423	394	367	342	240	169
GILBY - JURASSIC B	3.7	1.8	1.9	376	359	335	312	291	271	253	235	219	204	191	134	94
GILBY - MANNVILLE B	1.4	.7	.7	103	100	96	92	89	85	82	78	75	72	69	56	45
GILBY - VIKING A	2.6	2.3	.2	68	64	58	53	49	45	41	37	34	31	29	18	0
INNISFAIL - D-3	11.8	8.9	3.0	1682	1600	1338	977	712	520	379	277	202	147	107	0	0
MEDICINE RIVER - GLAUCONITIC A	2.0	.9	1.1	198	194	186	174	163	153	144	135	127	119	112	81	59
MEDICINE RIVER - JURASSIC A	2.0	1.3	.7	246	228	203	180	160	142	126	112	99	88	78	43	0

CONVENTIONAL CRUDE OIL - ESTABLISHED RESERVES AND PRODUCTIVE CAPACITY - NEB ESTIMATES

LIGHT CRUDE OIL

	INITIAL RECOVERABLE RESERVES	CUMULATIVE PRODUCTION TO 1/1/80	REMAINING RESERVES AT 1/1/80	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000
	(MILLION CUBIC METRES)			(CUBIC METRES PER DAY)												
MEDICINE RIVER - JURASSIC C	2.7	.9	1.8	189	188	187	183	177	170	164	158	153	147	142	118	98
MEDICINE RIVER - JURASSIC D	2.1	1.1	1.0	223	209	194	181	168	157	146	136	126	118	109	76	53
RICINUS - CARDIUM A	2.9	.6	2.3	265	256	247	237	229	220	212	204	197	189	182	151	125
SUNDRE - RUNDLE A	5.1	3.9	1.2	379	345	308	276	247	221	198	177	158	141	126	72	0
SYLVAN LAKE - PEKISKO B	2.3	1.0	1.3	268	265	263	251	230	212	195	179	164	151	139	91	59
WILLESDEN GREEN - CARDIUM A (30%)	9.0	3.7	5.3	626	620	614	597	570	544	519	495	472	451	430	341	270
OTHER	23.5	11.5	12.0	2659	2581	2505	2357	2149	1960	1787	1630	1486	1355	1236	779	491
PIPELINE TOTAL	78.0	41.0	37.0	8162	7865	7358	6648	5952	5362	4857	4419	4036	3698	3397	2264	1502
TEXACO EXPLORATION CANADA LTD.																
BONNIE GLEN - D-3A	73.1	52.3	20.8	12680	12061	9874	6883	4798	3345	2331	1625	1133	790	550	0	0
GLENPARK - D-3A	3.2	2.3	.9	370	333	283	240	204	173	147	125	106	90	76	34	2
WESTEROSE - D-3	21.2	12.4	8.8	2871	2814	2758	2510	2115	1782	1501	1265	1066	898	756	321	136
WIZARD LAKE - D-3A	51.3	34.7	16.6	8264	7629	7042	5858	4362	3248	2418	1801	1341	998	743	170	0
OTHER	1.7	1.5	.1	19	19	19	19	19	18	18	17	16	15	14	11	9
PIPELINE TOTAL	150.6	103.3	47.3	24207	22859	19979	15512	11499	8568	6418	4834	3663	2793	2143	537	147
TRANS-PRAIRIE PIPELINES LTD.: BOUNDARY LAKE SOUTH																
BOUNDARY LAKE SOUTH - TRIASSIC C	.6	.2	.4	63	60	57	54	51	48	46	44	41	39	37	29	22
BOUNDARY LAKE SOUTH - TRIASSIC E	3.8	1.5	2.3	481	445	413	382	354	328	304	281	261	241	224	152	104
OTHER	.3	.0	.2	69	64	58	51	46	41	37	33	29	26	23	13	7
PIPELINE TOTAL	4.7	1.7	3.0	614	571	528	488	452	419	388	359	332	308	285	195	134
TWINING PIPELINE DIVISION																
TWINING - RUNDLE A & LM A	4.8	1.7	3.1	507	482	458	434	408	385	362	341	321	302	285	210	156
TWINING NORTH - RUNDLE	1.3	.5	.8	252	236	210	187	167	149	133	119	106	94	84	47	26
OTHER	.6	.1	.5	34	33	32	32	31	30	29	29	28	27	26	23	20
PIPELINE TOTAL	6.7	2.3	4.4	794	752	702	654	607	565	525	489	455	425	396	282	204
VALLEY PIPE LINE																
TURNER VALLEY - RUNDLE & SHALLOW	25.5	20.7	4.8	490	470	454	441	429	417	405	393	382	371	361	312	270
PIPELINE TOTAL	25.5	20.7	4.8	490	470	454	441	429	417	405	393	382	371	361	312	270

CONVENTIONAL CRUDE OIL - ESTABLISHED RESERVES AND PRODUCTIVE CAPACITY - NEB ESTIMATES

LIGHT CRUDE OIL

	INITIAL RECOVERABLE RESERVES	CUMULATIVE PRODUCTION TO 1/1/80	REMAINING RESERVES AT 1/1/80	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000
	(MILLION CUBIC METRES)			(CUBIC METRES PER DAY)												
ALBERTA TRUCK AND TANK CAR																
TRUCK AND TANK CAR - TOTAL	1.0	.6	.4	73	71	68	63	58	54	50	47	43	40	38	26	18
PIPELINE TOTAL	1.0	.6	.4	73	71	68	63	58	54	50	47	43	40	38	26	18
ALBERTA TOTAL	1679.1	1082.5	596.6	164820	151832	136131	117966	102249	89462	78875	69494	61513	54773	48887	29361	18886
SASKATCHEWAN																
WESTSPUR - MEDIUM PIPE LINE - BATCHED LIGHT																
FLAT LAKE - RATCLIFFE, VOL. UNIT NO. 1	1.9	1.2	.8	190	175	161	148	136	126	116	106	98	90	83	55	36
FREDA LAKE - RATCLIFFE	.5	.3	.3	63	57	53	48	44	40	37	34	31	28	26	17	11
NEPTUNE - RATCLIFFE	.3	.2	.2	37	34	32	30	27	25	23	22	20	19	17	12	8
SHERWOOD - FROBISHER	1.8	1.5	.4	113	101	90	80	71	63	56	50	45	40	35	20	11
SKINNER LAKE - RATCLIFFE	.3	.1	.2	40	37	35	32	30	28	26	24	22	20	19	13	9
PIPELINE TOTAL	4.9	3.2	1.7	444	406	371	340	311	284	260	238	218	200	183	118	77
WESTSPUR PIPE LINE COMPANY - S.E. SASKATCHEWAN LIGHT																
ALIDA EAST - ALIDA, UNIT	2.0	1.7	.3	68	64	60	56	53	49	46	43	41	38	36	26	19
CARNDUFF - MIDALE, EAST UNIT	2.8	2.5	.3	107	98	90	82	75	69	63	58	53	48	44	0	0
ELMORE - FROBISHER, VOL. UNIT	2.2	1.4	.8	153	146	137	128	119	111	104	97	91	85	79	56	40
INGOLDSBY - FROBISHER ALIDA, VOL UNIT	2.7	2.0	.7	126	119	113	107	101	96	91	86	82	77	73	56	43
KENOSEE - TILSTON, VOL. UNIT	2.1	1.5	.6	260	231	196	166	141	120	102	86	73	62	53	9	0
PARKMAN - TILSTON SOURIS VALLEY	3.2	2.5	.7	204	190	171	155	140	127	115	104	94	85	77	46	0
QUEENSDALE EAST-FROBISHER ALIDA, NON-UNIT	4.8	3.4	1.4	367	337	306	277	251	228	207	187	170	154	140	85	52
ROSEBANK - FROBISHER ALIDA, VOL. UNIT NO. 1	3.6	3.3	.3	121	107	94	82	72	63	55	49	43	37	33	0	0
STEELMAN - MIDALE, UNIT IA	8.9	7.5	1.4	417	376	339	305	275	248	223	201	181	163	147	87	37
STEELMAN - MIDALE, UNIT II	8.4	7.1	1.3	330	306	280	256	234	214	196	179	163	149	137	87	56
STEELMAN - MIDALE, UNIT III	4.3	3.6	.8	219	200	181	165	150	136	123	112	102	92	84	51	17
STEELMAN - MIDALE, UNIT IV	5.4	4.1	1.3	384	350	316	284	256	231	208	188	169	152	137	81	48
STEELMAN - MIDALE, UNIT VI	8.8	8.2	.6	274	231	197	168	143	122	104	88	75	64	55	0	0
WILLMAR - FROBISHER ALIDA, NON-UNIT	3.2	2.3	.9	249	229	208	190	173	158	144	131	119	109	99	62	0
WORKMAN - FROBISHER, VOL. UNIT NO. 1	1.8	1.5	.3	115	105	96	87	79	72	65	59	54	49	45	0	0
OTHER	44.4	34.8	9.6	2682	2551	2362	2128	1918	1728	1557	1402	1263	1138	1026	609	361
PIPELINE TOTAL	108.7	87.5	21.2	6084	5647	5152	4645	4188	3779	3410	3079	2780	2512	2270	1262	676
SASKATCHEWAN TOTAL	113.6	90.7	22.9	6528	6053	5524	4985	4500	4063	3671	3317	2999	2712	2453	1381	753

CONVENTIONAL CRUDE OIL - ESTABLISHED RESERVES AND PRODUCTIVE CAPACITY - NEB ESTIMATES

LIGHT CRUDE OIL

	INITIAL RECOVERABLE RESERVES	CUMULATIVE PRODUCTION TO 1/1/80	REMAINING RESERVES AT 1/1/80	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000
	(MILLION CUBIC METRES)								(CUBIC METRES PER DAY)							
TRANS-PRAIRIE PIPELINES LTD.																
DALY-MISSISSIPPIAN	3.7	3.0	.7	204	190	173	158	144	131	119	108	99	90	82	51	19
NORTH VIRDEN SCALLION - MISSISSIPPIAN	11.2	8.3	2.8	671	616	566	520	478	439	403	370	340	312	287	188	123
ROUTLEDGE - MISSISSIPPIAN	2.7	2.1	.6	131	124	116	109	102	96	90	84	79	74	69	50	36
VIRDEN ROSELEA - MISSISSIPPIAN	7.5	5.3	2.2	406	390	371	348	327	307	289	271	255	239	225	164	120
OTHER	1.7	1.2	.5	117	113	105	96	87	79	72	66	60	55	50	31	19
PIPELINE TOTAL	26.8	20.0	6.9	1532	1435	1333	1233	1140	1054	975	902	834	772	714	486	319
MANITOBA TOTAL	26.8	20.0	6.9	1532	1435	1333	1233	1140	1054	975	902	834	772	714	486	319
ONTARIO																
ONTARIO - TOTAL	9.7	8.9	.8	246	220	197	177	158	142	127	114	102	91	82	47	27

CONVENTIONAL CRUDE OIL - ESTABLISHED RESERVES AND PRODUCTIVE CAPACITY - NEB ESTIMATES

HEAVY CRUDE OIL

	INITIAL RECOVERABLE RESERVES	CUMULATIVE PRODUCTION TO 1/1/80	REMAINING RESERVES AT 1/1/80	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000
	(MILLION CUBIC METRES)			(CUBIC METRES PER DAY)												
ALBERTA																
BOW RIVER PIPELINES LTD.: HEAVY																
BANTRY - MANNVILLE A	6.5	4.2	2.3	568	532	485	442	403	367	334	305	278	253	231	145	91
BANTRY - MANNVILLE D	1.3	.7	.6	121	115	109	101	94	88	82	76	71	66	62	43	30
COUNTESS - UPPER MANNVILLE B	1.1	.7	.3	152	130	111	95	81	70	59	51	43	37	32	0	0
COUNTESS - UPPER MANNVILLE D	6.0	2.9	3.1	1099	981	853	742	645	561	488	424	369	321	279	139	69
COUNTESS - UPPER MANNVILLE H	2.4	1.4	1.0	336	310	279	243	213	186	162	142	124	108	94	48	0
COUNTESS - UPPER MANNVILLE O	.9	.3	.6	141	132	122	113	104	96	89	82	76	70	64	43	29
GRAND FORKS - UPPER MANNVILLE B	1.2	.4	.8	306	272	234	201	172	148	127	109	93	80	69	32	1
GRAND FORKS - LOWER MANNVILLE D	5.4	2.1	3.3	1371	1182	1009	862	736	628	536	458	391	334	285	129	0
GRAND FORKS - LOWER MANNVILLE K	1.5	.5	.9	399	380	335	274	223	182	149	121	99	81	66	24	0
HAYS - LOWER MANNVILLE A	1.6	1.1	.6	217	196	171	149	130	114	99	87	76	66	58	29	0
LATHOM - UPPER MANNVILLE A	1.9	1.1	.8	320	301	269	227	192	162	137	116	98	83	70	30	0
TABER - MANNVILLE D	2.0	1.3	.8	214	193	175	158	143	129	117	106	95	86	78	47	28
TABER SOUTH - MANNVILLE A	1.0	.7	.3	85	77	69	62	56	51	46	41	37	33	30	18	0
TABER SOUTH - MANNVILLE B	1.9	1.6	.3	146	127	106	89	74	62	52	43	36	30	25	0	0
OTHER	12.9	6.2	6.6	2633	2505	2238	1873	1568	1313	1099	920	770	644	539	221	0
PIPELINE TOTAL	47.5	25.3	22.2	8116	7438	6570	5637	4842	4163	3583	3087	2663	2300	1989	954	251
BP EXPLORATION CANADA LIMITED																
CHAUVIN - MANNVILLE A	1.2	.9	.3	95	86	78	71	65	59	54	49	44	40	37	23	14
CHAUVIN SOUTH - SPARKY A & B	1.8	.8	1.0	178	174	167	157	147	138	130	122	115	108	101	74	54
CHAUVIN SOUTH - SPARKY E	.4	.2	.2	78	70	61	52	45	39	34	29	25	21	18	9	0
CHAUVIN SOUTH - SPARKY H	.6	.2	.4	138	124	108	95	83	73	64	56	49	43	37	19	0
CHAUVIN SOUTH - LLOYDMINSTER D	.3	.2	.1	33	30	28	26	23	22	20	18	17	15	14	9	0
DAVID - LLOYDMINSTER A	.5	.2	.3	112	100	87	76	66	57	50	43	37	32	28	14	7
OTHER	1.0	.4	.6	224	202	173	148	127	108	93	79	68	58	49	22	10
PIPELINE TOTAL	5.9	2.9	3.0	861	790	705	627	559	499	446	399	357	320	288	172	86
HUSKY PIPELINE LTD. & MANITO PIPELINES LTD.																
LLOYDMINSTER - SPARKY C & GP A	1.4	.9	.5	102	96	90	84	79	74	69	65	61	57	54	39	28
LLOYDMINSTER - SPARKY & GP C	3.6	2.1	1.5	269	256	241	227	214	202	190	179	168	159	149	111	82
VIKING-KINSELLA - WAINWRIGHT B	4.4	1.7	2.7	1216	1034	867	727	610	512	429	360	302	253	213	88	0
WAINWRIGHT - WAINWRIGHT & SPARKY A	11.6	6.7	4.9	1102	1033	955	882	815	753	696	643	594	549	507	341	230
WILDMERE - LLOYDMINSTER A & SPARKY B	2.4	.7	1.8	277	263	249	236	224	212	201	190	180	170	161	123	94
OTHER	4.4	2.0	2.4	925	848	724	619	529	452	386	330	282	240	205	93	39
PIPELINE TOTAL	27.8	14.1	13.7	3894	3532	3129	2778	2473	2206	1973	1769	1590	1431	1292	798	474

CONVENTIONAL CRUDE OIL - ESTABLISHED RESERVES AND PRODUCTIVE CAPACITY - NEB ESTIMATES

HEAVY CRUDE OIL

	INITIAL RECOVERABLE RESERVES	CUMULATIVE PRODUCTION TO 1/1/80	REMAINING RESERVES AT 1/1/80	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000
	(MILLION CUBIC METRES)			(CUBIC METRES PER DAY)												
ALBERTA TRUCK AND TANK CAR																
CESSFORD - TOTAL	5.1	3.1	2.0	588	546	490	440	395	355	319	286	257	231	207	121	70
OTHER	4.6	2.2	2.4	425	417	400	375	351	329	309	289	271	254	238	173	125
PIPELINE TOTAL	9.7	5.3	4.5	1013	963	890	815	747	685	628	576	529	486	446	294	196
ALBERTA TOTAL	90.9	47.6	43.4	13886	12725	11296	9860	8622	7554	6631	5832	5140	4539	4016	2219	1008

SASKATCHEWAN

	INITIAL RECOVERABLE RESERVES	CUMULATIVE PRODUCTION TO 1/1/80	REMAINING RESERVES AT 1/1/80	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000
HUSKY PIPELINE LTD. & MANITO PIPELINES LTD.																
ABERFELDY - SPARKY, ABERFELDY UNIT	6.0	4.0	2.0	462	427	396	367	340	314	291	270	250	231	214	146	99
SOUTH ABERFELDY - SPARKY	1.7	1.2	.5	152	137	124	112	101	91	82	74	67	60	54	25	0
DULWICH - SPARKY	2.0	1.5	.5	107	101	95	90	85	81	77	72	69	65	61	47	35
EPPING - SPARKY & G.P., NON-UNIT	2.4	1.6	.8	214	201	186	172	159	147	136	126	117	108	100	68	0
EPPING SOUTH - SPARKY & G.P., UNIT NO. 1	2.9	2.1	.8	237	214	193	174	157	142	128	116	104	94	85	51	30
EPPING S.W. - SPARKY UNIT	1.0	.6	.4	119	108	98	89	80	73	66	60	55	49	45	28	0
FURNESS - SPARKY	.4	.3	.1	56	49	42	36	30	26	22	19	16	13	11	0	0
GOLDEN LAKE NORTH - VOL. UNIT	1.9	1.2	.7	191	176	162	149	137	126	116	106	98	90	83	54	36
GOLDEN LAKE NORTH - NON-UNIT	.6	.3	.3	118	114	105	91	78	68	59	51	44	38	33	9	0
GOLDEN LAKE SOUTH - SPARKY	.9	.3	.5	147	137	124	113	102	93	84	76	69	63	57	35	21
GOLDEN LAKE SOUTH - WASECA	1.8	.9	.9	313	288	254	224	197	173	153	135	118	104	92	48	26
GULLY LAKE - WASECA, VOL. UNIT NO. 1	.8	.5	.3	95	87	79	72	66	60	55	50	46	42	38	24	2
GULLY LAKE - WASECA, NON-UNIT	.8	.3	.5	166	153	135	119	105	93	82	73	64	57	50	27	0
LASHBURN - WASECA, VOL. UNIT	.7	.6	.1	33	30	27	25	23	21	19	17	16	14	13	0	0
LONE ROCK - SPARKY	1.3	1.1	.2	46	42	39	36	33	31	29	26	24	23	21	14	9
TANGLEFLAGS - TOTAL	7.0	1.2	5.8	931	894	859	817	768	722	679	638	600	564	530	390	286
OTHER	17.0	4.9	12.1	2450	2354	2262	2128	1960	1805	1662	1530	1409	1298	1195	791	524
PIPELINE TOTAL	49.2	22.6	26.7	5843	5521	5188	4820	4431	4074	3747	3447	3173	2921	2691	1763	1073
BOW RIVER PIPE LINE LTD. (HEAVY BLEND)																
COLEVILLE - BAKKEN	7.8	5.4	2.4	617	593	554	504	458	417	379	345	313	285	259	161	100
DODSLAND - VIKING, EAGLE LAKE VOL. UNIT	2.4	1.5	.9	167	160	151	142	134	127	119	113	106	100	95	71	53
DODSLAND - VIKING, GLENEATH UNIT	2.4	1.4	1.0	182	174	164	155	146	138	130	122	115	109	103	77	57
DODSLAND - VIKING, NON-UNIT	3.0	.9	2.1	512	481	437	397	361	328	298	271	246	224	203	126	78
EUREKA - VIKING, SOUTH UNIT	1.3	.9	.3	100	91	83	76	69	63	58	52	48	44	40	25	0
NORTH HOOSIER - BAKKEN, VOL. UNIT	1.0	.6	.4	119	109	100	91	84	76	70	64	59	54	49	31	0

CONVENTIONAL CRUDE OIL - ESTABLISHED RESERVES AND PRODUCTIVE CAPACITY - NEB ESTIMATES

HEAVY CRUDE OIL

	INITIAL RECOVERABLE RESERVES	CUMULATIVE PRODUCTION TO 1/1/80	REMAINING RESERVES AT 1/1/80	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000
	(MILLION CUBIC METRES)			(CUBIC METRES PER DAY)												
NORTH HOOSIER - BLAIRMORE, VOL. UNIT	.6	.4	.2	73	68	60	53	47	42	37	32	29	25	22	1	0
SMILEY-DEWAR - VIKING	4.9	3.6	1.3	214	203	192	182	173	164	155	147	140	132	125	96	74
OTHER	3.7	2.4	1.3	390	361	324	292	262	236	212	191	172	154	139	82	0
PIPELINE TOTAL	27.1	17.3	9.9	2377	2243	2070	1896	1738	1594	1462	1342	1232	1131	1039	673	363
SOUTH SASKATCHEWAN PIPE LINE COMPANY																
BATTRUM - ROSERAY, UNIT NO. 1	5.9	3.9	2.0	409	384	357	331	307	285	265	246	228	212	196	135	93
CANTUAR MAIN - CANTUAR, UNIT	4.3	3.2	1.1	370	334	297	263	234	207	184	163	145	128	114	62	0
CANTUAR - LOWER ROSERAY, UNIT	1.7	1.3	.4	160	142	126	112	99	88	78	69	61	55	48	0	0
DELTA - UPPER SHAUNAVON, UNIT 1	2.4	2.0	.4	162	146	129	115	101	90	80	71	62	55	49	0	0
DOLLARD - UPPER SHAUNAVON, UNIT	12.7	11.7	1.0	479	407	346	294	250	212	180	153	130	110	94	0	0
FOSTERTON - ROSERAY, MAIN UNIT	9.5	8.1	1.4	389	351	317	286	258	233	210	190	171	155	140	83	50
GULL LAKE NORTH - UPPER SHAUNAVON, UNIT	3.1	2.8	.3	152	135	117	102	88	77	66	58	50	43	38	0	0
INSTOW - UPPER SHAUNAVON, UNIT	7.6	6.5	1.1	429	374	325	283	247	215	187	163	142	123	107	54	0
MAIN SUCCESS - ROSERAY, MAIN UNIT	2.6	2.5	.2	89	78	69	60	53	47	41	36	9	0	0	0	0
NORTH PREMIER - ROSERAY, UNIT NO. 3	2.2	1.9	.2	137	114	96	80	67	56	47	39	16	0	0	0	0
RAPDAN - UPPER SHAUNAVON, UNIT	2.9	2.1	.9	239	218	199	182	166	152	138	126	115	105	96	61	39
SOUTH SUCCESS - ROSERAY, UNIT	3.9	3.1	.8	189	176	163	150	139	128	119	110	101	94	86	58	39
SUFFIELD - UPPER SHAUNAVON, UNIT NO. 2	.8	.5	.3	68	64	59	54	50	46	42	39	36	33	30	20	13
SUFFIELD - UNIT NO. 3	1.2	.9	.4	180	157	132	111	93	78	66	55	46	39	32	0	0
VERLO - ROSERAY, UNIT	2.1	1.0	1.1	305	278	253	231	210	191	174	159	145	132	120	75	47
OTHER	24.3	16.4	7.9	2058	1977	1847	1676	1520	1379	1251	1135	1030	934	848	521	320
PIPELINE TOTAL	87.4	68.0	19.4	5822	5344	4839	4337	3890	3491	3136	2818	2495	2225	2006	1074	604
WESTSPUR PIPE LINE COMPANY - S.E. SASKATCHEWAN MEDIUM																
BENSON - MIDALE, UNIT	1.8	1.2	.6	129	122	115	107	101	94	88	83	78	73	68	49	36
INNES - FROBISHER	2.0	1.5	.5	146	135	122	110	99	89	80	73	65	59	53	32	0
LOST HORSE HILL - FROBISHER ALIDA, NO. 1	2.1	1.7	.5	157	142	126	112	100	89	79	70	63	56	50	28	15
MIDALE - CENTRAL MIDALE, UNIT	17.4	13.3	4.1	858	807	749	696	647	601	558	519	482	448	416	288	199
MIDALE - CENTRAL MIDALE, NON-UNIT	1.3	.8	.4	148	135	120	106	95	84	75	67	59	53	47	26	0
OUNGRE - RATCLIFFE, VOL. UNIT 1	1.9	.8	1.1	141	136	130	125	119	114	110	105	101	97	93	75	61
VIEWFIELD - FROBISHER, NON-UNIT	1.7	.6	1.1	199	190	179	168	157	148	138	130	121	114	107	77	56
WEYBURN - MIDALE, UNIT	52.8	37.2	15.6	2548	2448	2330	2196	2070	1951	1839	1733	1633	1539	1451	1079	802
WEYBURN - MIDALE, NON-UNIT	1.2	.8	.5	151	145	134	118	105	92	82	72	64	56	50	27	0
OTHER	13.4	9.6	3.9	1137	1092	1008	893	792	702	622	551	488	433	384	209	114
PIPELINE TOTAL	95.8	67.4	28.3	5620	5356	5018	4637	4289	3969	3676	3406	3159	2931	2721	1894	1286
SASKATCHEWAN TOTAL	259.5	175.3	84.3	19664	18465	17115	15692	14349	13130	12022	11015	10060	9210	8458	5405	3327
CANADA - TOTAL LIGHT CRUDE OIL	1918.1	1256.2	661.9	179412	165645	149098	130003	113354	99736	88341	78093	69367	61903	55423	33572	21674
CANADA - TOTAL HEAVY CRUDE OIL	350.5	222.8	127.6	33550	31191	28412	25552	22971	20684	18654	16848	15200	13749	12475	7625	4336
CANADA - TOTAL CRUDE OIL	2268.6	1479.0	789.5	212962	196836	177510	155555	136325	120420	106995	94941	84567	75652	67898	41197	26010

OPERATING COSTS FOR CONVENTIONAL CRUDE OIL PRODUCTION IN ALBERTA – NEB FORECAST

Introduction

The Board is concerned about the implications of continuing rapid escalation in operating costs on production from established reserves and therefore endeavoured to develop a procedure to forecast operating costs which explicitly takes into consideration the factors which determine real operating costs. Historical operating costs experienced in the last two decades are shown in Table L-1.

From an investigation of various forecasting procedures and correlations, the Board concludes that a reliable forecasting equation must in addition to the fixed costs, recognize the following factors as major determinants in real unit operating costs:

—the effect of prorationing on well productivity and on unit costs;
—the level of oil production;
—the gross volume of fluid (oil and water) lifted and handled;
—the number of operated oil wells.

Board's Methodology for Forecasting Operating Costs

Based on the above considerations, the Board developed the following equation to project real operating costs in the short term:

$$\text{Operating Costs Per Cubic Metre of Oil} = \frac{\text{No. of Wells} \times \text{Fixed Costs Per Well} + \text{Total Fluid Produced} \times \text{Cost/m}^3\text{ of Fluid Produced}}{\text{Production of Oil}}$$

Using the above equation, the Board has forecast unit oil operating costs as follows.

1. Industry's average fixed costs per well and average variable cost per cubic metre of fluid produced were estimated from data available for 1980. The values estimated were $50,860 per well and $1.30 per cubic metre of fluid handled. As this division of costs varies significantly by geological horizon, it would remain valid in the future only if the relative contribution to oil supply of each geological formation remains near current values.
2. The estimated average fixed costs per well and variable costs per cubic metre of fluid produced were used in the equation in conjunction with the number of producing wells, total fluid produced, and total crude production in 1980 to estimate 1980 operating costs per cubic metre of oil produced.
3. Real unit operating costs (expressed in 1980 dollars) were forecast to the year 1985 using the Board's estimates of 1980 fixed costs per well and variable cost per cubic metre of fluid produced, and the Board's forecast of crude production to the year 1985. The relationship between water oil ratio and cumulative oil production as shown in Figure L-1 was used to estimate fluid production. The number of operating oil wells was then calculated by assuming that average fluid production per well will not exceed 31.8 cubic metres per day. It was also assumed that no prorationing would occur in the forecast period.
4. The real operating costs were then escalated by the following inflation rates in each of the forecast years to calculate current dollar operating costs:

   1981 – 11.5%
   1982 – 10.5%
   1983 – 10.0%
   1984 – 10.0%
   1985 – 10.0%

   These inflation rates are somewhat higher than the rates assumed in the base case economic forecast for Canada, and reflect probable higher inflation rates in the oil industry.

Results

Tables L-2 to L-4 illustrate the Board's projections of real and current operating costs and the underlying factors which affect these costs – oil and water production, water oil ratios, and the number of operating wells – for three cases. Table L-2 illustrates Case I, which gives operating costs for oil produced from established reserves plus reserves additions. Tables L-3 and L-4 which illustrate Case II and Case III respectively, provide operating costs for oil produced from established reserves as of 31 December 1980. Case II differs from Case III because of a lower forecast of water production and fewer operating wells.

The Board's estimates of current dollar operating costs from established reserves, Cases II and III, indicate that operating costs in 1985 may be 3.3 to 4 times higher than those in 1980. These estimates are consistent with the Alberta Energy Resources Conservation Board's expectation that unit operating costs will triple or even quadruple within the next five years.

The Board's estimates of current dollar operating costs from established reserves and reserves additions indicate that operating costs in 1985 may be 2.8 higher than those in 1980.

Table L-1

TRENDS IN OPERATING COSTS FOR CONVENTIONAL CRUDE OIL IN ALBERTA

Year	Annual Production—(10^6m^3) Oil	Fluid	Water/Oil Ratio	Operating Oil Wells	Average Prod. Per Well—(m^3/d) Oil	Fluid	GNE Index 1980=100	Annual Operating Costs x10^6$	1980 x10^6$	Operating Costs Per Well x10^3$	1980 x10^3$	Operating Cost Per m^3 of Oil $	1980$	Operating Cost Per m^3 of Fluid $	$1980
1961	25.1	29.7	.19	8 938	7.6	9.1	32.7	57	174	6.4	19.5	2.27	6.92	1.89	5.79
1962	26.3	31.6	.20	9 183	7.8	9.4	33.2	57	172	6.2	18.7	2.20	6.61	1.82	5.47
1963	26.8	33.0	.23	9 217	7.9	9.9	33.8	57	169	6.2	18.3	2.14	6.29	1.70	5.03
1964	27.8	35.0	.26	9 617	7.9	10.0	34.6	62	179	6.4	18.6	2.20	6.36	1.76	5.10
1965	29.9	37.0	.24	8 736	9.4	11.6	35.8	63	176	7.2	20.1	2.08	5.79	1.70	4.72
1966	33.6	40.3	.21	8 886	10.3	12.4	37.3	67	180	7.5	20.3	2.01	5.41	1.64	4.41
1967	38.4	45.8	.20	9 116	11.6	23.8	38.8	75	193	8.2	21.2	1.95	4.97	1.64	4.22
1968	41.3	49.0	.19	9 114	12.4	14.8	40.1	82	204	9.0	22.4	2.01	5.03	1.70	4.22
1969	45.5	54.1	.19	9 381	13.3	15.7	41.9	87	208	9.3	22.2	1.89	4.53	1.64	3.90
1970	52.5	63.8	.216	9 382	15.3	18.6	43.8	105	240	11.2	25.6	2.01	4.59	1.64	3.71
1971	56.7	71.2	.256	9 425	16.5	20.7	45.2	135	299	14.3	31.7	2.39	5.29	1.89	4.15
1972	67.5	85.3	.265	9 578	19.2	24.5	47.5	156	328	16.3	34.2	2.33	4.91	1.82	3.84
1973	83.0	106.3	.281	9 859	23.0	29.6	51.8	211	407	21.4	41.3	2.58	4.97	2.01	3.90
1974	79.1	108.9	.377	10 101	21.5	29.6	59.7	261	437	25.8	43.3	3.27	5.47	2.39	4.03
1975	67.5	103.1	.528	10 499	17.6	26.9	66.1	318	481	30.3	45.8	4.72	7.11	3.08	4.66
1976	60.9	100.8	.657	10 898	15.3	25.4	72.4	397	548	36.4	50.3	6.54	9.06	3.96	5.47
1977	60.5	110.4	.825	11 362	14.6	26.7	77.5	481	621	42.3	54.7	7.93	10.26	4.34	5.60
1978	60.0	119.2	.985	11 851	13.8	27.5	82.4	596	723	50.3	61.0	9.94	12.08	4.97	6.04
1979	68.5	144.1	1.105	12 470	15.1	31.6	91.0	767	843	61.5	67.6	11.20	12.33	5.35	5.85

Table L-2

Case I
OPERATING COSTS FOR ALBERTA CRUDE OIL PRODUCED FROM ESTABLISHED RESERVES PLUS RESERVES ADDITIONS

	Annual Oil Production	Cum. Oil Prod. to Year-end	Annual Water Production	Annual Fluid Production	WOR	No. of Operating Wells	Operating Cost $/$m^3$ Oil Real	Current[1]
	10^6 m^3							
1980	63.2	1 193.2	94.1	157.3	1.49	13 312	13.95	13.95
1981	61.8	1 255.0	115.6	177.4	1.87	15 013	16.09	17.94
1982	56.7	1 311.7	128.5	185.2	2.27	15 673	18.30	22.55
1983	51.7	1 363.4	136.9	188.6	2.65	15 961	20.44	27.70
1984	47.1	1 410.5	140.5	187.6	2.98	15 876	22.32	33.27
1985	43.8	1 454.3	143.4	187.2	3.27	15 842	23.95	39.28

[1] Note: Expected inflation in each of the forecast years is as follows:
1981—11.5%
1982—10.5%
1983—10.0%
1984—10.0%
1985—10.0%

Table L-3

Case II
OPERATING COSTS FOR ALBERTA CRUDE OIL PRODUCED FROM ESTABLISHED RESERVES AT 31 December 1980

	Annual Oil Production	Cum. Oil Prod. to Year-end	Annual Water Production	Annual Fluid Production	WOR	No. of Operating Wells	Operating Cost $/m³ Oil	
		10^6m^3					Real	Current(1)
1980	63.3	1 193.2	94.1	157.3	1.49	13 312	13.95	13.95
1981	60.1	1 253.3	115.4	175.5	1.92	14 852	16.36	18.24
1982	53.8	1 307.1	128.0	181.8	2.38	15 385	18.94	23.34
1983	46.7	1 353.8	135.9	182.6	2.91	15 453	21.91	29.69
1984	40.5	1 394.3	138.9	179.4	3.43	15 182	24.82	37.00
1985	35.4	1 429.7	140.9	176.3	3.98	14 920	27.91	45.77

(1) Note: Expected inflation in each of the forecast years is as follows:
1981—11.5%
1982—10.5%
1983—10.0%
1984—10.0%
1985—10.0%

Table L-4

Case III
OPERATING COSTS FOR ALBERTA CRUDE OIL PRODUCED FROM ESTABLISHED RESERVES AT 31 December 1980

	Annual Oil Production	Cum. Oil Prod. to Year-end	Annual Water Production	Annual Fluid Production	WOR	No. of Operating Wells	Operating Cost $/m³ Oil	
		10^6m^3					Real	Current(1)
1980	62.3	1 193.2	94.1	157.3	1.49	13 312	13.95	13.95
1981	60.1	1 253.3	120.8	180.9	2.01	15 309	16.87	18.81
1982	53.8	1 307.1	144.2	198.0	2.68	16 756	20.62	25.41
1983	46.7	1 353.8	159.7	206.4	3.42	17 467	24.22	33.57
1984	40.5	1 394.3	175.4	215.9	4.33	18 271	29.87	44.54
1985	35.4	1 429.7	184.1	219.5	5.20	18 576	34.75	56.99

(1) Note: Expected inflation in each of the forecast years is as follows:
1981—11.5%
1982—10.5%
1983—10.0%
1984—10.0%
1985—10.0%

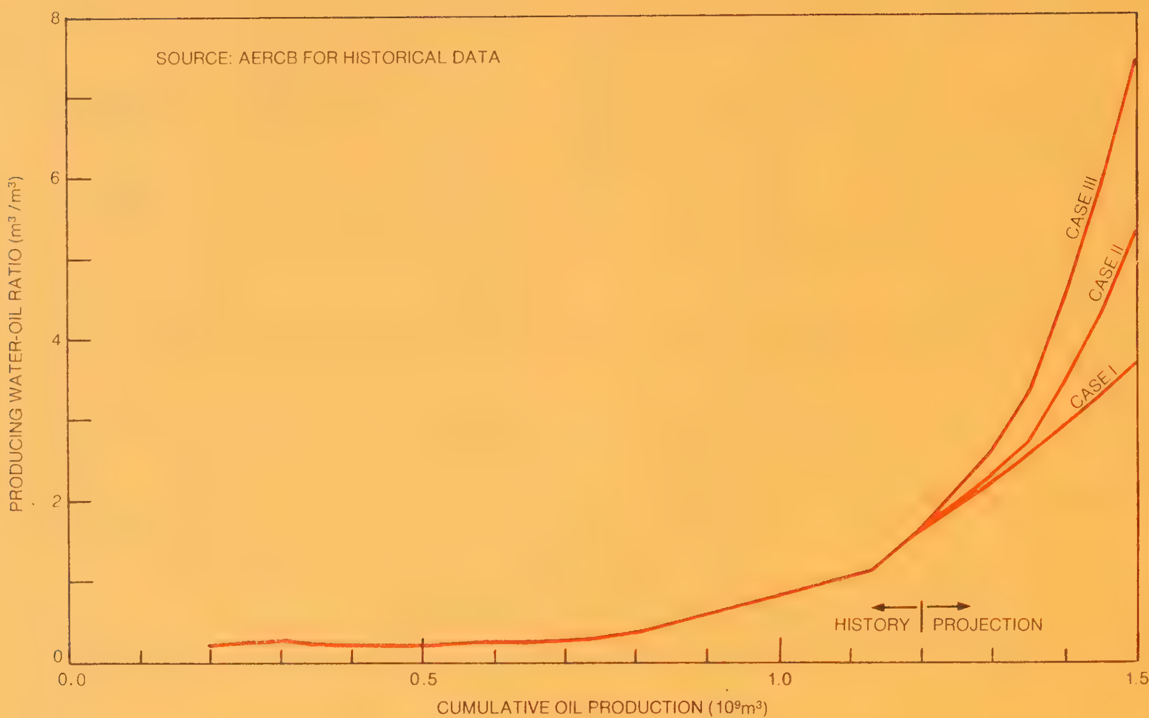

Figure L-1 Trend in Water-Oil Ratio's for Conventional Alberta Production

PENTANES PLUS PRODUCTION FROM GAS PLANTS

NEB Forecast

(m³/d)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000
From Established Reserves												
British Columbia												
Total	400	450	450	440	435	430	425	383	348	317	198	124
Alberta												
Bow River Pipe Lines												
Cessford (HBOG)	13	12	10	9	8	7	6	5	5	4	2	0
Empress (Petro-Canada)	355	363	363	363	363	363	363	363	363	363	236	27
Wayne Rosedale	27	27	27	26	26	26	25	25	24	24	21	12
Others	60	58	56	54	51	46	42	39	35	32	19	11
Total	455	460	456	452	448	442	436	432	427	423	278	50
Co-ed Pipe Line												
Cochrane	206	238	266	261	254	223	200	202	162	151	92	50
Edmonton Ethane	70	76	82	82	83	151	151	150	102	101	104	101
Empress (Dome)	276	276	276	276	276	276	276	276	276	276	0	0
Ferrier (Texas Pacific)	30	27	24	21	19	17	15	13	12	10	6	0
Garrington	27	20	14	12	8	6	3	1	1	0	0	0
Leduc — Woodbend	53	51	50	49	49	49	49	49	50	51	40	36
Minnehik-Buck Lake	135	135	135	119	103	89	78	68	59	52	27	14
Niton (Esso)	14	15	16	16	16	16	16	16	16	16	15	7
Pembina (Texaco)	9	9	9	8	8	7	7	7	6	6	5	4
Quirk Creek	99	94	91	88	86	81	77	73	70	67	42	26
Ricinus	177	148	123	106	91	77	82	76	69	65	42	38
Ricinus West (Aquitaine)	200	276	274	267	259	246	231	218	208	209	142	85
Strachan (Gulf)	550	550	507	430	359	308	265	227	196	169	79	39
Others	21	21	20	20	20	20	20	20	19	18	13	6
Total	1867	1936	1887	1755	1631	1566	1470	1396	1246	1191	607	406
Cremona Pipeline												
Burnt Timber	47	52	51	50	49	48	48	47	46	44	26	15
Carstairs (Home)	359	339	308	272	240	212	187	166	147	130	72	31
Crossfield (Petrogas)	250	222	195	172	152	134	119	106	94	84	48	26
Crossfield East	96	74	59	49	40	35	30	27	23	20	14	9
Harmattan	693	686	680	671	635	587	546	510	459	394	186	90
Lone Pine Creek (Can. Sup.)	30	27	25	23	21	19	17	16	15	13	9	6
Lone Pine Creek (HBOG)	134	134	131	127	124	121	118	116	113	111	102	50

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000
Olds	62	58	53	49	46	43	40	37	34	32	23	18
Others	5	5	5	4	4	4	4	3	3	3	2	1
Total	1676	1597	1507	1417	1311	1203	1109	1028	934	831	482	246
Federated Pipe Lines												
Total	7	8	8	8	8	8	7	7	7	6	5	5
Gibson Petroleum												
Acheson	28	27	25	20	17	14	12	10	9	8	4	4
Connorsville	13	12	12	11	9	7	6	5	4	3	0	0
Ferrybank (PanCanadian)	19	19	19	19	19	19	18	16	14	12	7	4
Leaman (Dome)	17	17	16	12	9	7	6	5	5	4	0	0
Okotoks	12	12	12	12	12	12	12	12	12	12	7	4
Paddle River	79	79	79	79	79	79	73	65	58	51	28	15
Wilson Creek	19	18	17	16	16	15	14	14	13	12	10	9
Worsley	28	19	14	11	9	7	6	5	5	4	0	0
Others	13	11	10	9	8	7	6	5	4	4	2	0
Total	228	214	204	189	178	167	153	137	124	110	58	36
Gulf Alberta Pipe Line												
Ghost Pine (Gulf)	85	85	85	85	77	69	62	56	51	45	27	16
Hussar (CDC)	33	35	35	35	35	35	35	35	35	35	32	22
Nevis (Chevron)	52	38	28	20	15	11	0	0	0	0	0	0
Nevis (Gulf)	177	164	150	135	102	90	80	71	64	57	32	17
Others	60	56	54	50	48	46	45	42	40	38	27	23
Total	407	378	352	325	277	251	222	204	190	175	118	78
Imperial Pipe Line — Ellerslie												
Golden Spike	67	58	54	51	49	47	45	60	52	40	11	3
Others	18	17	14	12	10	8	7	6	5	5	3	1
Total	85	75	68	63	59	55	52	66	57	45	14	4
Imperial Pipe Line — Leduc												
Judy Creek	692	614	547	488	437	391	351	316	284	269	199	107
Total	692	614	547	488	437	391	351	316	284	269	199	107
Imperial Pipe Line — Redwater												
Redwater	65	50	38	29	22	20	19	17	16	15	10	9
Total	65	50	38	29	22	20	19	17	16	15	10	9
Murphy Oil												
Total	14	13	13	12	11	11	10	10	10	9	8	7

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000
Peace River Oil Pipe Line												
Carson Creek	193	175	158	144	143	135	125	112	96	80	34	12
Dunvegan	102	88	77	67	59	52	45	40	35	30	12	4
Gold Creek	110	105	99	96	92	86	78	70	63	57	30	19
Greencourt	15	15	15	14	14	14	14	13	13	13	8	4
Josephine	15	15	15	15	14	12	11	10	9	8	5	3
Kaybob	63	55	48	43	37	32	29	25	22	20	11	5
Kaybob South (Chevron)	1997	1798	1617	1450	1299	1514	1319	1151	1006	880	456	240
Kaybob South (HBOG)	1419	1205	1011	836	690	553	434	344	274	177	15	9
Simonette (Shell)	32	31	31	29	27	26	25	24	23	21	10	4
Sturgeon Lake South	64	59	54	50	46	42	39	36	33	31	20	14
Whitecourt	29	29	29	29	29	28	28	25	21	19	10	5
Windfall	486	423	375	361	348	311	241	186	145	113	35	11
Others	64	64	69	72	70	69	67	64	62	59	45	38
Total	4589	4062	3598	3206	2868	2874	2455	2100	1802	1508	691	368
Pembina Pipe Line												
Brazeau (CDC)	46	41	35	30	26	24	21	19	17	15	9	6
Brazeau (HBOG)	251	243	235	227	218	194	171	151	134	119	68	40
Peco	51	48	45	42	37	33	30	26	24	21	13	8
Willesden Green	25	24	23	22	20	19	17	16	14	13	8	4
Others	17	16	16	16	14	13	12	10	9	9	3	2
Total	390	372	354	337	315	283	251	222	198	177	101	60
Rainbow Pipe Line												
Cranberry	181	169	152	145	135	126	117	111	98	88	41	21
Mitsue (Chevron)	97	90	84	79	73	68	63	58	53	49	32	19
Nipisi	103	92	83	74	66	59	53	48	43	38	22	13
Swan Hills (Shell)	12	11	10	10	9	8	8	7	7	6	5	4
Rainbow	241	221	203	187	173	159	146	139	129	119	178	155
Total	634	583	532	495	456	420	387	363	330	300	278	212
Rangeland Pipe Line												
Caroline (Altana)	45	42	40	37	35	33	32	30	29	27	18	10
Caroline (HBOG)	88	79	71	64	58	52	47	43	38	35	21	13
Ferrier (Amerada)	161	147	131	116	103	91	81	72	64	57	31	17
Gilby (Chevron)	24	23	23	21	18	16	14	12	11	9	5	3
Gilby (Texaco)	64	63	63	62	62	57	52	47	42	38	19	10
Gilby (Others)	59	55	52	50	47	44	42	38	37	34	18	10
Innisfail	59	49	41	34	28	23	19	16	13	11	4	0
Pincher Creek	109	89	0	0	0	0	0	0	0	0	0	0
Sylvan Lake (Chevron)	37	34	32	30	29	28	24	21	19	17	11	6
Sylvan Lake (Gen. Am.)	41	36	33	30	27	24	22	20	18	16	9	6
Sylvan Lake (HBOG)	36	31	28	25	23	20	17	14	12	10	5	2
Sylvan Lake (Others)	21	20	18	17	17	15	14	14	12	12	8	2
Waterton	1259	1291	1343	1310	1218	1065	881	749	648	570	376	185
Wimborne	61	54	48	43	38	34	30	27	24	21	12	7
Others	26	24	21	19	17	16	14	13	12	11	9	6
Total	2090	2037	1944	1858	1720	1518	1289	1116	979	868	546	277

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000
Rimbey Pipeline												
Homeglen — Rimbey	719	586	479	393	326	272	229	147	115	64	55	20
Total	719	586	479	393	326	272	229	147	115	64	55	20
Texaco Exploration												
Bonnie Glen	598	902	860	710	576	523	482	459	430	434	165	343
Total	598	902	860	710	576	523	482	459	430	434	165	343
Valley Pipe Line												
Jumping Pound	430	430	427	425	423	412	403	396	382	357	216	121
Turner Valley	49	45	42	39	36	33	30	28	26	24	16	11
Wildcat Hills	85	85	85	85	85	85	80	76	72	65	39	24
Total	564	560	554	549	544	530	513	500	480	446	271	156
Truck and Tank Car												
Boundary Lake South (Esso)	10	9	8	8	7	6	6	5	5	4	3	2
Edson	198	183	170	158	145	130	117	106	96	87	53	28
Pembina (Amoco)	103	99	95	91	87	83	80	77	74	71	61	51
Rosevear	56	56	56	56	56	56	56	56	56	56	56	33
Sundance	32	32	32	32	30	26	22	19	16	14	7	3
Twining	21	22	22	21	20	20	19	18	18	17	10	6
Vulcan	35	32	28	25	23	20	18	16	14	12	7	4
Others	227	210	194	179	166	153	142	131	121	112	76	52
Total	682	643	605	570	534	494	460	428	400	373	273	179
Alberta Total	15 762	15 090	14 006	12 856	11 721	11 028	9 895	8 948	8 029	7 244	4 159	2 563
Saskatchewan Total	102	96	90	77	65	55	47	40	36	32	18	11
Canada Sub-Total	16 264	15 636	14 546	13 373	12 221	11 513	10 367	9 371	8 413	7 593	4 375	2 698
From Unconnected Established Reserves and Reserves Additions	1 009	2 048	3 363	4 746	4 826	4 906	4 705	4 634	4 035	3 648	5 476	6 276
Canada Total*	17 273	17 684	17 909	18 119	17 047	16 419	15 072	14 005	12 448	11 241	9 851	8 974

*The above supply includes supply which will be required for EOR projects.

OIL SANDS SUPPLY
NEB Forecast
$10^3 m^3/d$

Year	Miscel-laneous In Situ	Suncor	Syncrude	Subtotal Base Case	Cold Lake In Situ	3rd Mining	Syncrude Expansion	Undefined Project	Undefined Project	Undefined Project	Undefined Project	Total High Case
1981	2	8	12	22	—	—	—	—	—	—	—	22
1982	3	9	16	28	—	—	—	—	—	—	—	28
1983	4	9	19	32	—	—	—	—	—	—	—	32
1984	4	9	20	33	—	—	—	—	—	—	—	33
1985	5	9	20	34	—	—	—	—	—	—	—	34
1986	5	9	20	34	—	—	—	—	—	—	—	34
1987	5	9	20	34	5	—	—	—	—	—	—	39
1988	5	9	20	34	14	1	—	—	—	—	—	49
1989	5	9	20	34	20	8	6	—	—	—	—	68
1990	5	9	20	34	22	16	8	—	—	—	—	80
1991	5	9	20	34	22	19	10	1	—	—	—	86
1992	5	9	20	34	22	19	10	8	—	—	—	93
1993	5	9	20	34	22	21	10	16	—	—	—	103
1994	5	9	20	34	22	21	10	21	1	—	—	109
1995	5	9	20	34	22	21	10	22	8	—	—	117
1996	5	9	20	34	22	21	10	22	16	—	—	125
1997	5	9	20	34	22	21	10	22	21	1	—	131
1998	5	9	20	34	22	26	10	22	22	8	—	144
1999	5	9	20	34	22	29	10	22	22	16	—	155
2000	5	9	20	34	22	31	10	22	22	21	1	163

POOLS SUBJECT TO MAJOR NEGATIVE REVISIONS IN 1980
NEB ESTIMATES OF
INITIAL ESTABLISHED MARKETABLE GAS RESERVES
(31 December 1980)
($10^6 m^3$)

Field	Pool	
Bluesky	Pool No. 1	20 855
Crossfield	Rundle B	22 700
Hairy Hill	St. Edouard A	1 321
Hairy Hill	St. Edouard B	210
Huxley	Viking A, Upper Mann. A and Lower Mann. A	1 140
Marten Hills	Wabiskaw A and Wabamum A	16 530
Pembina	Cardium (solution gas)	17 000
Quirk Creek	Rundle A	7 875
Simonette	D-3 (solution gas)	1 714
Strachan	D-3A	27 627
Swan Hills South	BHL A and B (solution gas)	4 720
Westerose South	D-3A	35 130

POOLS LISTED IN ORDER NO. EHR-1-80
NEB ESTIMATES OF
INITIAL ESTABLISHED MARKETABLE GAS RESERVES
(31 December 1980)

(10^6m^3)

Alberta

Field	Pool	
Aden	Rundle A	435
Atlee-Buffalo	Viking B	64
Basing	Turner Valley	1 086
Bellis	Nisku A	1 343
Belloy	Notikewin A	701
Belloy	Debolt A	772
Belloy	Debolt C	749
Benjamin	Rundle A	
		4 274
Benjamin	Rundle B	
Bindloss	Viking B	72
Birch	Camrose B	522
Blueridge	Jurassic B	1 468
Burnt Timber	Wabamun A	2 761
Calling Lake	D-2B	1 487
Carson Creek	Beaverhill Lake A	4 790
Carson Creek	Beaverhill Lake B	2 250
Cessford	Viking D & H	1 017
Cessford	Basal Colorado E	2 340
Cessford	Mannville C	1 580
Cessford	Mannville H	1 290
Chinchaga	Slave Point A	552
Coleman	Rundle A	4 193
Coleman	Palliser A	590
Coleman	Palliser B	1 010
Connorsville	Viking A	144
Craigend	Grosmont A	3 610
Cranberry	Slave Point A	7 338
Crimson	D-3A	1 280
Crossfield	Rundle A	25 200
Crossfield	Basal Quartz A	1 080
Crossfield	East Wabamun A	12 864
Crossfield	East Elkton A	1 230
Donalda	Viking A, C & D	409
Eaglesham	Debolt A	580
Edson	Gething A	5 070
Enchant	Basal Colorado A	689
Esther	Banff A	750
Fairydell-Bon Accord	Basal Mannville A	112
Ferrier	Cardium D	3 578
Ferrier	Cardium E	9 000
Ferrybank	Lower Mannville A & B	598
Figure Lake	Upper Mannville B & D-2B	1 410
Fir	Triassic A	5 122
Fir	Gething A	515
Fir	D-3A	517
Fox Creek	Viking A	2 920
Fox Creek	Cadomin	1 030
Gilby	Basal Mannville H, L, Jurassic-Rundle & Upper Mannville A	11 600
Gilby	Basal Mannville D	1 440
Gilby	Basal Mannville A & Jurassic D	5 400

Field	Pool	
Gladys	Crossfield 20-27	1 281
Gold Creek	Cadomin B	175
Gold Creek	Bluesky-Gething A	840
Gold Creek	Wabamun A	1 130
Granor	Grosmont A	850
Greencourt	Jurassic A	3 399
Greencourt	Pekisko A	1 835
Hanlan	Swan Hills 47-17	16 113
Heart River	Notikewin	430
Holmberg	Glauconitic A	200
Hunter Valley	Rundle A	1 785
Hussar	Viking B	295
Hussar	Ostracod F	65
Hussar	Ostracod R	594
Hussar	Basal Mannville B2	4
Jarrow	Glauconitic I	620
Jumping Pound West	Rundle A & B	27 400
Kaybob	Notikewin A	6 140
Kaybob	Notikewin B	4 360
Kaybob	SouthCadomin A	555
Kaybob	SouthCadomin B	331
Kaybob	SouthCadomin C	688
Kaybob	SouthCadomin D	737
Kaybob	SouthBeaverhill Lake A	38 243
Kirby	Upper Mannville A	569
Kirby	Clearwater C 74-05	969
Liege	Grosmont A	800
Limestone	Rundle A	6 632
Limestone	Rundle B	643
Limestone	Wabamun 32-0	9798
Limestone	Wabamun 33-10	1 150
Limestone	Leduc 36-32-10	1 259
Limestone	Leduc 14-33-10	471
Lone Pine Creek	Wabamun A	8 200
Lone Pine Creek	D-3A	2 239
Lookout Butte	Rundle A	5 400
Lovett River	Rundle A	1 615
Medicine Lodge	Viking A	635
Medicine River	Pekisko P	400
Minehead	Beaverhill Lake 49-19	2 219
Mountain	Triassic 36-47-22	505
Nevis	Devonian	17 300
Okotoks	Crossfield	5 000
Olds	Wabamun A (Associated)	4 690
Olds	Wabamun C	722
Oyen	Viking A & Detrital C	720
Paddle River	Jurassic-Detrital-Rundle	11 000
Pembina	Lobstick Glauconitic A (Associated)	3 500
Pembina	Lobstick Glauconitic C & D	1 615
Pine Creek	Wabamun	1 870
Pine Creek	Wabamun C	1 560
Pine Creek	D-3	4 875
Pine North West	D-3A	2 292
Pouce Coupe	Peace River A	3 380
Provost	Mannville Z	675
Retlaw	Mannville B & D	1 310
Richdale	Viking A & C	1 884
Rowley	Pekisko A (Associated)	1 140
Salter	Mount Head 26-08	
Salter	Turner Valley 26-08	1 775

Field	Pool	
Savanna Creek	Rundle A	3 940
Shaw	Rundle	700
Sinclair	Doig A	9 987
Standard	Viking A	285
Stanmore	Viking A & B	1 010
Sylvan Lake	Elkton-Shunda B	810
Virginia Hills	Belloy A	2 040
Waterton	Rundle C	3 660
Waterton	Rundle D & E	6 300
Waterton	Rundle A & H	1 090
Waterton	Rundle-Wabamun A	42 000
Waterton	Wabamun B	482
Whitecourt	Pekisko E	2 100

British Columbia

Field	Pool	
Buick Creek	Dunlevy A	
Buick Creek	Dunlevy B	6 578
Buick Creek	Dunlevy C	
Bullmoose	Baldonnel A	3 164
Cabin	Slave Point A	
Cabin	Slave Point B	979
Cabin	Slave Point C	
Clarke Lake	Slave Point A	31 163
Grizzly North	Halfway A	
		5 666
Grizzly North	Halfway B	
Grizzly South	Dunlevy A	1 745
Helmet	Slave Point A	6 412
Kotcho Lake	Slave Point A	1 521
Kotcho Lake	Slave Point C	614
Kotcho Lake East	Slave Point C	2 506
Louise	Slave Point	615
Oak	Halfway A	1 417
Petitot River	Slave Point	576
Sierra	Elk Point A	16 571
Sierra	Elk Point B	8 584
Silver	Bluesky A	2 113
Sukunka	Baldonnel A	
		3 487
	Baldonnel C	
Sukunka	Baldonnel B	442
Velma	Gething	1 192
Yoyo	Elk Point A	34 800

Northwest Territories

Field	Pool	
Pointed Mountain	Nahanni	7 920

PROPANE AND BUTANES PRODUCTION FROM GAS PLANTS

NEB Forecast

(m^3/d)

	Propane								Butanes							
	1981	1982	1983	1984	1985	1990	1995	2000	1981	1982	1983	1984	1985	1990	1995	2000
From Established Reserves																
British Columbia																
Total	215	220	220	215	210	153	96	61	265	280	280	275	270	197	123	78
Alberta																
Acheson	99	84	69	56	45	19	8	8	62	55	45	36	29	12	5	5
Ante Creek (Amoco)	16	16	30	41	39	23	8	1	11	11	20	29	27	16	5	1
Bigoray (Chevron)	19	18	17	15	14	9	5	3	10	9	9	8	7	4	3	2
Bonnie Glen (Texaco)	780	1566	1514	1150	778	354	148	584	495	1051	1017	762	550	268	69	286
Brazeau (Petro-Canada)	21	19	18	17	15	10	7	5	12	11	10	10	9	6	4	3
Campbell-Namao	25	23	20	18	16	8	0	0	16	14	12	10	8	4	0	0
Caroline (Altana)	19	18	16	15	14	12	9	5	18	17	16	15	15	12	9	5
Caroline (HBOG)	45	41	37	33	30	18	11	7	59	54	49	44	40	25	15	9
Carson Creek	251	220	191	166	144	63	28	13	201	180	162	146	132	85	36	13
Carstairs	282	267	244	216	192	108	62	27	202	192	176	156	138	77	44	19
Cranberry	55	55	55	55	55	46	31	21	61	60	58	56	54	37	25	16
Crossfield (Petrogas)	168	144	127	112	99	54	30	13	119	105	93	82	73	40	22	10
Ferrier (Amerada)	257	236	209	185	164	90	48	26	138	127	113	100	89	49	26	14
Ferrier (Esso)	16	16	16	16	16	14	10	7	14	14	14	14	14	13	9	7
Ferrier (Texas Pacific)	12	11	9	8	7	4	2	0	16	15	13	12	10	6	3	0
Garrington	73	54	40	30	22	1	0	0	45	33	25	18	14	1	0	0
Gilby (Chevron)	7	7	7	7	6	3	2	1	9	9	9	9	8	4	2	1
Gilby (Texaco)	71	70	70	69	68	42	23	12	65	64	64	63	62	38	22	13
Golden Spike	137	120	113	107	103	91	26	8	98	86	80	77	74	64	18	5
Harmattan East	378	365	356	347	297	72	30	13	275	264	244	234	225	49	17	6
Homeglen — Rimbey	763	617	514	432	366	112	103	32	495	398	330	276	232	54	47	15
Hussar (CDC)	55	57	57	57	57	57	53	36	41	44	44	44	44	44	41	27
Joffre (Esso)	13	12	11	10	10	7	5	2	10	9	8	8	7	5	3	1
Judy Creek	1724	1529	1361	1214	1086	679	526	281	1016	900	800	713	637	387	276	152
Jumping Pound	72	68	64	62	61	53	34	20	90	88	86	84	83	77	45	26
Kaybob (Petro-Canada)	145	127	111	97	85	45	25	12	87	76	66	58	51	27	14	8
Kaybob South (Chevron)	518	481	446	414	385	231	99	46	552	522	493	467	442	268	119	57
Kaybob South (HBOG)	365	307	275	238	198	74	24	14	459	390	348	299	247	78	15	9
Leaman	13	13	12	11	11	8	6	5	11	10	9	9	8	6	5	4
Leduc — Woodbend	80	75	70	65	60	50	50	50	95	91	87	83	79	71	71	71
Minnehik-Buck Lake	1	1	1	1	1	0	0	0	14	14	12	11	10	5	3	1
Mitsue	214	199	186	174	162	109	70	42	143	134	125	117	110	74	47	28
Nevis (Chevron)	47	35	25	19	14	0	0	0	39	30	22	16	12	0	0	0
Nevis (Gulf)	324	266	214	175	156	76	49	33	194	161	133	112	105	56	40	27
Nipisi	154	138	124	111	100	59	34	20	161	145	130	116	104	61	36	21
Niton (Esso)	20	22	23	23	23	23	21	10	17	18	19	19	19	19	17	8
Olds (Amerada)	47	44	41	38	36	24	17	12	31	29	27	25	23	16	12	8
Paddle River	176	176	176	176	176	114	63	34	89	89	89	89	89	58	32	17
Pembina (Amoco)	241	232	223	214	205	171	142	121	164	158	152	146	140	114	95	80

	Propane								Propane							
	1981	1982	1983	1984	1985	1990	1995	2000	1981	1982	1983	1984	1985	1990	1995	2000
Pembina (Cities Service)	11	11	12	12	12	12	10	9	13	13	13	13	12	11	9	8
Pembina (Texaco)	18	18	17	16	15	12	10	8	18	17	17	16	15	12	10	8
Pincher Creek	45	38	0	0	0	0	0	0	35	29	0	0	0	0	0	0
Quirk Creek	101	98	95	93	91	75	52	33	74	72	70	68	67	55	38	24
Rainbow	721	661	688	634	587	404	604	526	502	460	479	441	408	281	420	366
Redwater	192	131	100	76	58	32	22	19	128	94	71	54	41	28	19	17
Ricinus (Amoco)	175	148	127	109	95	73	48	45	99	79	67	59	51	39	26	24
Simonette (Shell)	24	19	15	12	10	1	1	0	25	23	21	19	17	12	5	2
Strachan (Gulf)	159	137	118	100	86	40	19	9	149	129	111	94	80	37	17	8
Sturgeon Lake South	9	8	8	7	6	4	3	2	9	9	8	7	7	4	3	2
Swan Hills	56	52	48	45	42	30	20	12	36	34	32	29	28	19	14	9
Sylvan Lake (Chevron)	57	50	46	43	41	24	14	9	36	32	29	27	26	15	9	6
Sylvan Lake (HBOG)	61	52	46	41	36	15	6	2	37	32	27	24	21	8	3	1
Turner Valley	83	76	70	65	61	40	28	20	65	62	57	53	49	36	23	14
Twining (Mobil)	15	15	16	15	14	12	7	4	11	11	11	11	10	9	5	3
Waterton	312	325	351	318	312	206	136	68	312	321	345	312	308	188	117	56
Willesden Green (Texaco)	16	15	13	12	11	6	4	2	11	10	9	8	7	4	2	1
Other Plants	148	137	127	117	108	73	50	34	95	87	81	72	64	45	36	24
Cochrane	1313	1518	1712	1676	1635	971	591	319	429	496	556	544	531	316	192	104
Edmonton Ethane	1059	1241	1261	1179	1125	517	555	517	334	368	376	369	362	176	198	186
Empress (Total)	3216	3257	3257	3341	3425	3425	1336	153	1441	1459	1459	1459	1459	1459	556	64
Alberta Total	15 494	15 756	15 219	14 105	13 086	8 905	5 325	3 315	9 493	9 514	9 048	8 252	7 583	4 984	2 954	1 902
Saskatchewan Total	161	148	135	124	113	74	50	20	69	64	61	57	54	39	28	13
Canada Sub-Total	15 870	16 124	15 574	14 444	13 409	9 132	5 471	3 396	9 827	9 858	9 389	8 584	7 907	5 220	3 105	1 993
From Unconnected Established Reserves & Reserves Additions	759	1 534	2 538	4 073	4 442	3 079	5 175	6 172	530	1 071	1 771	2 706	2 963	2 060	3 261	3 803
Canada Total*	16 629	17 658	18 112	18 517	17 851	12 211	10 646	9 568	10 357	10 929	11 160	11 290	10 870	7 280	6 366	5 796

*The above supply includes supply which will be required for EOR projects.

PROPANE PRODUCTION FROM REFINERIES
NEB Forecast
(m³/d)

	1981	1982	1983	1984	1985	1990	1995	2000
Region I	391	405	406	403	383	322	329	324
Region II	818	816	822	800	792	871	885	880
Region III	1 305	1 361	1 345	1 345	1 267	1 211	1 202	1 258
Region IV	982	1 009	1 010	1 042	1 121	1 214	1 329	1 445
Region V	325	336	350	353	360	391	413	495
Total Canada	3 821	3 927	3 933	3 943	3 923	4 009	4 158	4 402

BUTANES PRODUCTION FROM REFINERIES
NEB Forecast
(m³/d)

	1981	1982	1983	1984	1985	1990	1995	2000
Region I	38	43	43	43	41	34	35	34
Region II	432	435	441	430	425	576	583	586
Region III	1 077	1 126	1 120	1 120	1 063	1 033	1 041	1 107
Region IV	588	609	614	645	699	757	841	900
Region V	218	229	242	253	262	290	312	377
Total Canada	2 353	2 442	2 460	2 491	2 490	2 690	2 812	3 004

ESTIMATE OF ELECTRICITY GENERATED BY MAJOR FUEL TYPE (GW.h)

Province: Newfoundland & Labrador

Fuel Type	1980	1985	1990	1995	2000
Hydro	44 860	40 724	45 454	45 454	56 754
Coal	—	—	—	418	—
Oil & Gas	1 398	2 296	173	797	173
Nuclear	—	—	—	—	—
Total	46 258	43 020	45 627	46 669	56 927
Domestic Electricity Demand	8 429	10 790	12 984	15 716	19 318
Net Export from Province	37 829	32 230	32 643	30 954	37 609

Sources: 1) Electricity in Canada—Update 1980 (EM & R Publication)
2) NEB In-House Estimates for 1985—2000

Province: Nova Scotia

Fuel Type	1980	1985	1990	1995	2000
Hydro	903	1 082	1 082	1 082	1 082
Coal	1 508	4 762	8 259	9 644	11 365
Oil & Gas	4 452	2 689	692	712	858
Nuclear	—	—	—	—	
Total	6 863	8 588	10 098	11 518	13 395
Domestic Electricity Demand	6 809	8 838	10 098	11 517	13 394
Net Export from Province (Import to)	54	(250)	—	1	1

Sources: 1) Electricity in Canada— Update 1980 (EM & R Publication)
2) NEB In-House Estimates for 1985— 2000

Province: Prince Edward Island

Fuel Type	1980	1985	1990	1995	2000
Hydro	—	—	—	—	—
Coal	—	—	—	290	613
Oil & Gas	127	150	150	175	140
Nuclear	—	—	—	—	—
Total	127	150	150	465	753
Domestic Electricity Demand	515	687	794	983	1 225
Net (Import to) Province	(388)	(537)	(644)	(518)	(472)

Sources: 1) Electricity in Canada—Update 1980 (EM & R Publication)
2) NEB In-House Estimates for 1985—2000

ESTIMATE OF ELECTRICITY GENERATED BY MAJOR FUEL TYPE (GW.h)

Province: New Brunswick

Fuel Type	1980	1985	1990	1995	2000
Hydro	2 666	2 692	2 692	2 692	2 822
Coal	457	1 482	1 256	1 839	1 305
Oil & Gas	6 160	1 533	1 397	2 753	1 594
Nuclear	—	4 415	4 408	4 415	8 830
Other		10	10	10	10
Total	9 283	10 132	9 763	11 709	14 561
Domestic Electricity Demand	8 808	10 408	12 142	14 214	16 981*
Net Export from Province (Import to)	475	(276)	(2 379)	(2 505)	(2 550)

Sources: 1) Electricity in Canada—Update 1980 (EM & R Publication)
2) NEB In-House Estimates for 1985—2000
*Does not include 130 GW.h for operation of pumped storage.

Province: Québec

Fuel Type	1980	1985	1990	1995	2000
Hydro	97 560	121 067	144 587	160 297	174 579
Coal	—	—	—	—	—
Oil & Gas	247	480	483	483	483
Nuclear	—	2 964	2 964	2 964	2 964
Total	97 807	124 511	157 328	176 668*	205 008*
Domestic Electricity Demand	118 151	138 051	157 328	176 668*	205 008*
Net Export from Province (Import to)	(20 344)	(13 540)	(9 294)	(13 734)	(26 982)

Sources: 1) Electricity in Canada—Update 1980 (EM & R Publication)
2) NEB In-House Estimates for 1985—2000
*Does not include 800 GW.h and 1600 GW.h for operation of pumped storage.

Province: Ontario

Fuel Type	1980	1985	1990	1995	2000
Hydro	40 191	38 889	38 889	38 889	39 939
Coal	28 912	33 201	37 261	48 212	51 777
Oil & Gas	5 142	4 305	4 550	5 180	5 883
Nuclear	35 880	61 839	72 435	78 609	103 305
Total	110 125	138 234	153 135	170 890	200 904
Domestic Electricity Demand	106 317	122 696	136 294	158 390	188 904
Net Export from Province (Import to)	3 808	15 538	16 841	12 500	12 000

Sources: 1) Electricity in Canada—Update 1980 (EM & R Publication)
2) NEB In-House Estimates for 1985—2000

ESTIMATE OF ELECTRICITY GENERATED BY MAJOR FUEL TYPE (GW.h)

Province: Manitoba

Fuel Type	1980	1985	1990	1995	2000
Hydro	19 096	20 607	20 607	20 627	25 156
Coal	99	—	—	—	—
Oil & Gas	268	81	81	81	87
Nuclear	—	—	—	—	—
Total	19 462	20 708	20 708	20 708	25 243
Domestic Electricity Demand	13 949	15 789	17 675	19 341	22 555
Net Export from Province (Import to)	5 513	4 919	3 033	1 367	2 688

Sources: 1) Electricity in Canada—Update 1980 (EM & R Publication)
2) NEB In-House Estimates for 1985—2000

Province: Saskatchewan

Fuel Type	1980	1985	1990	1995	2000
Hydro	2 549	2 759	3 829	3 829	5 411
Coal	5 816	7 859	8 102	10 355	11 455
Oil & Gas	823	422	488	542	626
Nuclear	—	—	—	—	—
Other	—	40	40	40	40
Total	9 188	11 080	12 459	14 766	17 532
Domestic Electricity Demand	9 812	11 280	12 559	14 166	17 432
Net Export from Province (Import to)	(624)	(200)	(100)	600	100

Sources: 1) Electricity in Canada—Update 1980 (EM & R Publication)
2) NEB In-House Estimates for 1985—2000

Province: Alberta

Fuel Type	1980	1985	1990	1995	2000
Hydro	1 699	1 637	1 637	1 637	5 947
Coal	16 855	27 031	33 156	45 625	55 615
Oil & Gas	4 838	3 318	5 086	4 027	3 880
Nuclear	—	—	—	—	—
Total	23 392	31 986	39 879	51 289	65 442
Domestic Electricity Demand	23 114	31 829	39 781	49 664	63 234
Net Export from Province (Import to)	278	157	98	1 625	2 208

Sources: 1) Electricity in Canada—Update 1980 (EM & R Publication)
2) NEB In-House Estimates for 1985—2000

ESTIMATE OF ELECTRICITY GENERATED BY MAJOR FUEL TYPE (GW.h)

Territory: Yukon

Fuel Type	1980	1985	1990	1995	2000
Hydro	322	388	538	688	838
Coal	—	—	—	—	—
Oil & Gas	63	85	72	94	165
Nuclear	—	—	—	—	—
Total	384	473	610	782	1 003
Domestic Electricity Demand	384	473	610	782	1 003
Net Export from Province (Import to)	nil	nil	nil	nil	nil

Sources: 1) Electricity in Canada—Update 1980 (EM & R Publication)
2) NEB In-House Estimates for 1985—2000

Province: British Columbia

Fuel Type	1980	1985	1990	1995	2000
Hydro	40 860	58 514	58 514	58 514	59 324
Coal	—	1 200	2 600	6 939	20 033
Oil & Gas	2 474	2 016	2 612	4 297	5 444
Nuclear	—	—	—	—	—
Other	206	938	1 197	1 528	1 950
Total	43 334	62 668	64 923	71 278	86 751
Domestic Electricity Demand	42 702	51 504	59 850	70 402	85 700
Net Export from Province (Import to)	632	11 164	5 073	876	1 051

Sources: 1) Electricity in Canada—Update 1980 (EM & R Publication)
2) NEB In-House Estimates for 1985—2000

Terrritory: Northwest Territories

Fuel Type	1980	1985	1990	1995	2000
Hydro	292	267	327	327	623
Coal	—	—	—	—	—
Oil & Gas	163	234	321	511	458
Nuclear	—	—	—	—	—
Total	455	501	648	838	1 081
Domestic Electricity Demand	455	501	648	838	1 081
Net Export from Province (Import to)	nil	nil	nil	nil	nil

Sources: 1) Electricity in Canada—Update 1980 (EM & R Publication)
2) NEB In-House Estimates for 1985—2000

ALLOWANCE GIVEN FOR NATURAL GAS EXPORT LICENCES
(Petajoules)

			1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Firm Licences																	
South From Alberta	A&S	GL-3*(2)	182.0	182.0	182.0	182.5	182.0	158.6	34.7								
		GL-16*(2)	89.8	89.8	89.8	90.0	89.8	89.8	89.8	83.6	43.8						
		GL-24*(1)	93.7	93.7	93.7	93.9	93.7	93.7	93.7	93.9	93.7	93.7	86.1	48.5	40.4		
		GL-35*(1)	81.4	81.4	81.4	81.6	73.9	33.6	15.3								
	CMPL	GL-5*(1)	14.3	14.3	14.3	14.3	14.3	12.4	2.5								
		GL-17*(2)	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	7.8						
		GL-25*(2)	9.5	9.5	9.5	9.5	9.5	9.2	6.8								
		GL-36*(1)	4.8	4.8	4.8	4.8	4.3	1.8	0.8								
		GL-52	10.4	10.4	10.4	10.4	7.8	5.2	2.6								
		GL-53						1.7	1.7								
		GO-3-79	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.1				
	WTCL	GL-4*(1)	60.0	55.8	55.4	53.1	39.3	25.4	11.5								
	PAG	GL-58	53.9	322.4	322.4	309.0	228.3	147.7	67.1								
		GL-59	96.7	96.7	96.7	9.76	8.54	4.3	20.1								
		GL-62				13.4	94.1	145.3	54.8								
		GL-63	13.2	13.2	15.0	28.2	45.7	39.7	62.3								
	Total South		719.6	983.9	985.3	993.3	961.1	818.3	473.6	187.4	145.7	94.1	86.2	48.5	40.4		
B.C.	WTCL	GL-41*(1)	329.7	329.7	329.7	329.7	329.7	329.7	329.7	329.7	274.6						
		CGDC	GL-54	14.5	14.5	14.5	14.5	10.9	7.2	3.6							
	TOTAL	B.C.	344.2	344.2	344.2	344.2	340.6	336.9	333.3	329.7	274.6						
East of Alberta	ICG	GL-28*(2)	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	0.9
		GL-29*(2)	12.5	12.5	12.5	12.6	12.5	12.5	12.5	12.6	12.5	12.5	12.5	12.6	12.5	12.5	10.4
	NGL	GL-6	6.9	6.9	6.9	6.9	6.4	1.8									
		GL-55	3.3	3.3	3.3	3.2	2.9	4.7	2.1								
	TCPL	GL-1**(1)	5.6														
		GL-18**(1)(3)	120.3	58.6	58.6	58.7	58.6	58.6	58.6	58.7	48.8						
		GL-19**(2)	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	6.9						
		GL-20*(1)	36.5	36.5	36.5	36.6	36.5	36.5	36.5	36.6	36.5	36.5	30.4				
		GL-37**(1)	76.0	76.0	76.0	76.2	76.0	76.0	76.0	76.2	76.0	63.3					
		GL-38**(1)	19.4	19.4	19.4	19.5	19.4	19.4	19.4	19.5	19.4	16.2					
		GL-39**(1)	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.3					
		GL-43**(1)	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	15.0				
		GL-60	78.7	78.7	78.7	75.4	54.3										
	PRO	GL-56	116.3	116.3	116.3	111.5	82.4	53.3	24.2								
	SULP	GL-57	27.7	19.2													
	CNG	GL-61	77.6	77.6	77.6	74.4	55.0	35.6	16.2								
	Total East		611.0	535.2	516.0	505.2	434.2	328.6	275.7	233.8	222.1	150.0	59.0	13.7	13.6	13.6	11.3
Canada	Total		1 674.8	1 863.3	1 845.3	1 842.7	1 735.9	1 483.8	1 082.6	750.9	642.4	244.1	145.2	62.2	54.0	13.6	11.3
Extended Licences																	
South From Alberta	PAG	GL-58						29.4	200.4	268.7							
		GL-59							16.2	80.6							
		GL-63					6.7	36.8	18.2								
	Total South		719.6	983.9	985.3	993.3	967.8	884.5	708.4	536.7	145.7	94.1	86.2	48.5	40.4		
Canada	Total		1 674.8	1 863.3	1 845.5	1 842.7	1 742.6	1 550.0	1 317.4	1 100.2	642.4	244.1	145.2	62.2	54.0	13.6	11.3

*Including provision for annual averaging at maximum daily licensed rate (adjusted for heat content), times the number of days in the year, as permitted by existing conditions in the licence.

**Assuming export at maximum annual licensed rate (adjusted for heat content).

(1) Allowance was made for annual exports until the expiry of the term of the licence.

(2) Allowance was made for annual exports until that point in time at which the remaining term volumes would have been exhausted if the licensee were to export at the level of the annual licensed quantity (without recourse to any annual averaging permitted in the licence).

(3) Includes interruptible volumes under Licences 18, 20, 37.

NATURAL GAS LIQUIDS—NET EXPORT LICENCES

	Licence Number	Total Remaining	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Propane																	
Dome	GL-31	7.573	16.795	15.874	3.405	3.405	3.405	3.405	3.687	4.941	5.044	4.327	4.250	4.224	4.148	2.663	—
Amoco	GL-32	32.924	2.381	2.381	2.381	2.381	2.381	2.381	2.381	2.381	2.381	2.381	2.381	2.381	2.381	1.971	—
PanCanadian	GL-34	9.564	1.639	1.639	1.639	1.639	1.639	1.357	0.102	—	—	—	—	—	—	—	—
Total Canada		122.151	20.815	19.894	7.425	7.425	7.425	7.143	6.170	7.322	7.425	6.708	6.631	6.605	6.529	4.634	—
Ethane																	
Dome	GO-1-81	2.977	2.977	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dome	GL-47	124.046	38.217	29.100	26.160	22.048	8.521	—	—	—	—	—	—	—	—	—	—
Dome	GL-51	310.571	17.397	20.727	23.090	26.495	37.212	50.813	42.868	35.184	24.206	14.233	11.201	5.210	1.935	—	—
Total Canada		437.594	58.591	49.827	49.250	48.543	45.733	50.813	42.868	35.184	24.206	14.233	11.021	5.210	1.935	—	—
Ethylene																	
Dow	EYL-1-76	71.952	7.995	7.995	7.995	7.995	7.995	7.995	7.995	7.995	7.995	—	—	—	—	—	—
DOW	EYL-2-80	0.453	0.453	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Esso	EYL-2-79	0.378	0.284	0.094	—	—	—	—	—	—	—	—	—	—	—	—	—
Total Canada		72.783	8.832	8.089	7.995	7.995	7.995	7.995	7.995	7.995	7.995	—	—	—	—	—	—

NATURAL GAS SUPPLY/DEMAND BALANCE UNDER THE CURRENT DELIVERABILITY TEST

Tables SD-1 to SD-13, following, illustrate the detailed supply/demand balancing procedure used in the verification of the Board's Current Deliverability Test for the Base Case Supply and Middle Case Demand Scenario.

The total Canada natural gas balance is shown in Table SD-13.

TABLE SD-1

TOTAL DEMAND FOR CANADIAN NATURAL GAS

(PETAJOULES/YEAR)

	DOMESTIC					EXPORT			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
YEAR	NET SALES	DOMESTIC FUEL	NET REPROC	FUEL FOR EXPORTS	TOTAL DOMESTIC (1+2+3+4)	EXISTING EXPORTS	NEW EXPORTS	FUEL NEW EXPORTS	TOTAL DEMAND (5+6+7+8)
1981	1752	75	193	55	2076	1675	0	0	3751
1982	1821	79	200	57	2157	1863	0	0	4020
1983	1959	84	205	55	2304	1845	0	0	4150
1984	2062	89	249	55	2455	1843	0	0	4298
1985	2167	95	260	51	2572	1736	0	0	4308
1986	2231	99	261	43	2633	1484	0	0	4117
1987	2300	102	256	32	2691	1083	0	0	3773
1988	2385	105	236	24	2750	751	0	0	3501
1989	2506	110	219	21	2855	642	0	0	3498
1990	2538	114	213	9	2874	244	0	0	3118
1991	2574	116	203	5	2897	145	0	0	3043
1992	2624	118	198	2	2943	62	0	0	3005
1993	2668	121	198	2	2989	54	0	0	3043
1994	2737	124	200	1	3062	14	0	0	3075
1995	2816	129	198	1	3143	11	0	0	3155
1996	2885	132	197	0	3214	0	0	0	3214
1997	2951	135	195	0	3281	0	0	0	3281
1998	3041	139	194	0	3374	0	0	0	3374
1999	3140	143	192	0	3475	0	0	0	3475
2000	3246	148	190	0	3585	0	0	0	3585
TOTAL	50406	2257	4257	410	57330	13452	0	0	70782

-FIGURES MAY NOT ADD DUE TO ROUNDING.

-COLUMN 1 IS THE TOTAL DOMESTIC NET SALES IN CANADA .

-COLUMN 2 IS THE FUEL FOR THE DOMESTIC NET SALES.

-COLUMN 3 IS THE TOTAL REPROCESSING SHRINKAGE REQUIREMENTS FROM COLUMN 13,TABLE SD-3.

-COLUMN 4 IS THE FUEL FOR THE EXISTING FIRM EXPORTS.

-COLUMN 6 IS THE EXISTING FIRM EXPORTS NOT INCLUDING FUEL.

-COLUMN 7 REPRESENTS THE POSSIBLE NEW EXPORTS CONSIDERED IN THIS TEST.

-COLUMN 8 IS THE INCREMENTAL FUEL FOR THE NEW EXPORTS.

TABLE SD-2

DEMAND FOR CANADIAN GAS BY AREAS

(PETAJOULES/YEAR)

	ALBERTA						BRITISH COLUMBIA		EAST OF ALBERTA		TOTAL CANADA		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
YEAR	DOMESTIC	EXPORT	AGTL FUEL	NET REPROC	ANG FUEL	EAST LEG FUEL	DOMESTIC	EXPORT	DOMESTIC	EXPORT	DOMESTIC	EXPORT	TOTAL
											(1+3+4+5+6+7+9)	(2+8+10)	(11+12)
1981	574	720	21	193	7	1	195	344	1085	611	2076	1675	3751
1982	584	984	23	200	7	3	214	344	1125	535	2157	1863	4020
1983	661	985	23	205	7	3	233	344	1171	516	2304	1845	4150
1984	696	993	23	249	7	3	239	344	1237	505	2455	1843	4298
1985	720	961	23	260	7	3	251	341	1309	434	2572	1736	4308
1986	737	818	20	261	6	3	257	337	1349	329	2633	1484	4117
1987	763	474	15	256	4	1	263	333	1388	276	2691	1083	3773
1988	804	187	12	236	2	0	269	330	1428	234	2750	751	3501
1989	872	146	11	219	2	0	274	275	1478	222	2855	642	3498
1990	849	94	10	213	1	0	274	0	1526	150	2874	244	3118
1991	856	86	9	203	1	0	281	0	1548	59	2897	145	3043
1992	869	49	8	198	1	0	290	0	1577	14	2943	62	3005
1993	877	40	8	198	0	0	298	0	1607	14	2989	54	3043
1994	888	0	8	200	0	0	316	0	1649	14	3062	14	3075
1995	900	0	8	198	0	0	345	0	1692	11	3143	11	3155
1996	919	0	9	197	0	0	359	0	1730	0	3214	0	3214
1997	938	0	9	195	0	0	370	0	1770	0	3281	0	3281
1998	963	0	9	194	0	0	385	0	1822	0	3374	0	3374
1999	992	0	9	192	0	0	399	0	1884	0	3475	0	3475
2000	1022	0	10	190	0	0	412	0	1951	0	3585	0	3585
TOTAL	16485	6537	268	4257	53	18	5921	2992	30327	3923	57330	13452	70782

-FIGURES MAY NOT ADD DUE TO ROUNDING.

-COLUMNS 1 PLUS 3 REPRESENT THE TOTAL DOMESTIC DEMAND FOR GAS IN ALBERTA. COLUMN 1 INCLUDES THE FUEL AND LOSSES FOR DISTRIBUTION OF ALBERTA'S NET SALES OF GAS. COLUMN 3 IS THE FUEL REQUIREMENTS FOR AGTL FOR ALL GAS TRANSPORTED IN ITS SYSTEM LEAVING THE PROVINCE.

-COLUMN 2 IS THE TOTAL EXPORTS SOUTH FROM ALBERTA - ALBERTA AND SOUTHERN, WESTCOAST GL-4 AND PAN-ALBERTA WEST VIA KINGSGATE, BRITISH COLUMBIA; CANADIAN-MONTANA VIA CARDSTON AND ADEN, ALBERTA; AND PAN-ALBERTA EAST VIA MONCHY, SASK.

-COLUMN 4 IS THE TOTAL REPROCESSING SHRINKAGE REQUIREMENTS FROM COLUMN 13, TABLE SD-3.

-COLUMNS 5 AND 6 REPRESENT THE FUEL REQUIRED TO TRANSPORT THE EXPORTS ON THE ANG SYSTEM TO KINGSGATE AND THE PRE-BUILD EAST LEG TO MONCHY RESPECTIVELY.

-COLUMNS 7 AND 9 ARE THE CANADIAN REQUIREMENTS EXCLUDING ALBERTA. THEY INCLUDE FUEL AND LOSSES ASSOCIATED WITH TRANSMISSION AND DISTRIBUTION OUTSIDE ALBERTA .

-COLUMN 8 IS THE WESTCOAST GL-41 EXISTING EXPORTS PLUS THE COLUMBIA EXPORTS.

-COLUMN 10 IS THE TOTAL EXPORTS EAST OF ALBERTA - TCPL, ICG, NIAGARA, SULPETRO, CONSOLIDATED AND PROGAS.

-THE EXISTING EXPORTS IN COLUMNS 2, 8 AND 10 HAVE BEEN GIVEN THE FULL PROTECTION ALLOWED IN THE LICENCES.

TABLE SD-3

REPROCESSING PLANT SHRINKAGE AND FUEL
REQUIREMENTS
(PETAJOULES/YEAR)

	COCHRANE				EMPRESS				EDMONTON				
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
YEAR	ETHANE	NGL	FUEL	TOTAL (1+2+3)	ETHANE	NGL	FUEL	TOTAL (5+6+7)	ETHANE	NGL	FUEL	TOTAL (9+10+11)	TOTAL (4+8+12)
1981	29	17	5	50	47	55	13	115	14	14	0	28	193
1982	29	16	5	50	47	55	8	110	23	16	0	40	200
1983	36	16	3	55	47	55	8	110	24	16	0	41	205
1984	43	15	3	61	69	68	15	152	21	15	0	37	249
1985	41	14	3	58	84	68	15	166	20	15	0	35	260
1986	38	13	3	54	84	68	15	166	22	18	0	40	261
1987	36	12	3	51	84	68	15	166	21	18	0	39	256
1988	27	9	3	39	80	65	14	159	20	18	0	38	236
1989	24	8	2	35	82	66	14	163	13	8	0	21	219
1990	23	8	2	33	81	66	14	161	12	8	0	20	213
1991	21	7	2	30	77	63	14	154	11	7	0	19	203
1992	19	7	2	28	77	62	14	152	11	7	0	18	198
1993	17	6	2	25	78	63	14	156	10	7	0	18	198
1994	15	5	1	22	81	65	14	161	10	7	0	17	200
1995	11	4	1	16	83	67	15	165	8	8	0	17	198
1996	10	3	1	14	84	68	15	166	8	8	0	17	197
1997	9	3	1	12	84	68	15	166	8	8	0	16	195
1998	8	3	1	11	84	68	15	166	8	8	0	16	194
1999	6	2	1	9	84	68	15	166	8	8	0	16	192
2000	6	2	1	8	84	68	15	166	8	8	0	16	190
TOTAL	449	170	43	662	1520	1293	274	3087	278	222	8	508	4257

-THIS TABLE REPRESENTS THE BOARD'S FORECASTS OF EXPECTED REQUIREMENTS FOR REPROCESSING PLANT SHRINKAGES AND FUEL AT COCHRANE, EMPRESS AND EDMONTON.

-THE BOARD'S FORECAST OF SHRINKAGE AND FUEL AT COCHRANE, COLUMNS 1, 2 AND 3, IS BASED ON ITS ESTIMATE OF THE MAXIMUM THROUGHPUT AVAILABLE TO COCHRANE THROUGHOUT THE FORECAST PERIOD.

-THE BOARD'S FORECAST OF SHRINKAGE AND FUEL AT EMPRESS, COLUMNS 5, 6 AND 7, IS BASED ON THE TOTAL THROUGHPUT NECESSARY TO MEET REQUIREMENTS EAST OF ALBERTA FROM ALBERTA SUPPLIES THROUGHOUT THE FORECAST PERIOD.

-THE FORECAST OF SHRINKAGE AND FUEL AT EDMONTON, COLUMNS 9, 10 AND 11, IS BASED ON DOME'S SUBMISSION TO THE INQUIRY.

TABLE SD-4

CANADIAN GAS DELIVERABILITY FROM CONTROLLED RESERVES

(PETAJOULES/YEAR)

YEAR	(1) TCPL	(2) A+S	(3) WTCL GL41	(4) WTCL GL 4	(5) PAN ALTA	(6) SULFETRO SUPPLY	(7) PROGAS SUPPLY	(8) COLUMB SUPPLY	(9) PAN ALTA NEW GAS	(10) ALTA UTIL	(11) CAN MONTANA	(12) MIF	(13) PROD EAST ALTA	(14) TOTAL
REMAINING RESERVES AT 31 DECEMBER 1980	26645	7333	8235	189	1225	420	1337	163	5235	6149	251	613	1406	59201
1981	1768	586	483	41	106	27	79	14	116	366	11	19	59	3646
1982	1783	579	501	34	93	25	96	14	333	354	11	18	64	3859
1983	1786	558	491	29	81	24	103	14	436	342	11	20	60	3911
1984	1848	527	492	24	71	23	102	14	394	318	11	22	64	3857
1985	1778	494	489	13	62	22	99	14	356	286	11	22	63	3643
1986	1732	495	465	4	54	21	94	14	313	261	10	20	60	3471
1987	1616	454	428	4	48	21	86	14	274	234	10	18	57	3211
1988	1506	410	402	4	41	20	78	14	245	220	11	16	53	2973
1989	1402	371	367	4	36	20	70	14	217	201	10	15	50	2723
1990	1282	347	263	4	32	20	63	14	184	186	9	13	46	2412
1991	1139	320	270	4	27	17	56	14	161	174	8	11	44	2203
1992	1031	295	279	4	24	14	50	6	144	162	7	10	41	2010
1993	941	263	251	4	21	12	45	1	131	142	6	9	39	1791
1994	819	233	234	4	19	11	40	0	121	132	6	8	36	1528
1995	701	169	212	4	16	10	35	0	111	123	5	7	35	1386
1996	612	143	184	4	14	9	31	0	101	108	4	6	32	1238
1997	513	128	171	4	13	8	28	0	92	98	4	6	30	1086
1998	428	115	159	3	11	8	20	0	84	89	4	5	28	948
1999	352	99	145	0	10	7	18	0	77	81	4	4	25	820
2000	305	85	132	0	8	6	16	0	72	71	4	4	23	719
TOTAL	23343	6670	6418	189	785	322	1207	163	3961	3947	154	253	908	47437

-FIGURES DO NOT ADD BECAUSE THE EFFECT OF THE 1980 RESERVES REVISION, DESCRIBED IN THE SUPPLY CHAPTER, HAS BEEN CONSIDERED.

-NEB FORECASTS OF PRODUCTION FROM CONTRACTED RESERVES FOR TCPL (INCLUDING CONSOLIDATED), A+S, WESTCOAST GL-41, WESTCOAST GL-4, SULFETRO, PROGAS, COLUMBIA, PAN-ALBERTA (PERMIT PA 79-2) AND CANADIAN-MONTANA ARE IN COLUMNS 1, 2, 3, 4, 6, 7, 8, 9 AND 11 RESPECTIVELY.

-THE WESTCOAST GL-41 FORECAST INCLUDES ALL GAS IN THE WESTCOAST SUPPLY AREA EXCEPTING 0.5 EJ OF UNCOMMITTED RESERVES (I.E. THE 1980 RESERVES ADDITION).

-COLUMN 5 IS THE FORECAST OF PAN-ALBERTA'S AERCB PERMIT NO. PA 80-3 SUPPLY ADOPTED FROM PAN-ALBERTA.

-COLUMN 10 IS THE FORECAST OF ALBERTA UTILITIES' SUPPLY ADOPTED FROM THE CONSULTANT'S FORECAST FOR THE JOINT APPLICANTS TO HEARING GH-4-79. THIS FORECAST EXCLUDES THE SUPPLY FROM DEFERRED RESERVES CONTROLLED BY THE ALBERTA UTILITIES.

-COLUMN 12 IS THE FORECAST OF MANY ISLANDS PIPELINES' SUPPLY ADOPTED FROM THE SPC SUBMISSION TO THIS GAS INQUIRY.

-COLUMN 13, PRODUCTION EAST OF ALBERTA, INCLUDES THE FORECAST OF SASKATCHEWAN PRODUCTION FROM THE SPC SUBMISSION TO THIS GAS INQUIRY AND THE BOARD'S FORECAST OF ONTARIO PRODUCTION.

-REMAINING RESERVES AT 31 DECEMBER 1980 REPRESENT THE BOARD'S ESTIMATES BASED UPON AVAILABLE INFORMATION REGARDING CONTROLLED SUPPLIES.

TABLE SD-5

GAS SUPPLY AVAILABLE TO MEET ALBERTA DEMAND

(PETAJOULES/YEAR)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
YEAR	TOTAL DEMAND	ALBERTA SUPPLIES	TCPL ALTA SUPPLIES	DEFERRED SUPPLY	UNCOMMITTED SUPPLY	SUPPLY FROM BER RESERVES	ALBERTA TREND	TOTAL	SURPLUS
								(2+3+4+5+6+7)	(8-1)
1981	1516	1142	159	3	197	2	0	1502	-14
1982	1802	1301	160	3	276	3	0	1743	-59
1983	1885	1356	160	3	355	5	0	1879	-6
1984	1973	1228	164	4	434	7	0	1836	-137
1985	1974	1089	159	6	512	8	0	1775	-199
1986	1845	999	156	6	564	10	0	1735	-110
1987	1513	898	148	6	589	12	0	1653	139
1988	1240	809	141	12	598	14	0	1574	333
1989	1249	710	134	27	601	15	0	1488	239
1990	1168	710	125	42	593	17	0	1486	318
1991	1155	650	116	39	557	18	0	1379	224
1992	1125	579	108	35	525	19	0	1266	141
1993	1124	493	102	32	494	20	0	1141	17
1994	1096	379	94	28	456	21	0	978	-119
1995	1107	383	86	46	424	22	0	961	-146
1996	1124	361	80	45	391	23	0	901	-224
1997	1142	325	74	100	359	24	0	882	-260
1998	1166	296	68	97	326	24	0	812	-355
1999	1193	263	63	95	296	25	0	741	-452
2000	1221	227	60	112	270	26	0	695	-527
TOTAL	27619	14197	2357	740	8817	314	0	26426	-1193

-COLUMN 1 IS THE TOTAL ALBERTA DEMAND INCLUDING EXPORTS SOUTH FROM ALBERTA AND IS THE SUM OF COLUMNS 1 TO 6 ON TABLE SD-2.

-COLUMN 2 IS THE SUM OF THE ALBERTA UTILITIES FORECAST, THE A+S FORECAST LESS A+S COLUMBIA SALES, THE WESTCOAST GL-4 FORECAST, THE CANADIAN-MONTANA FORECAST, THE PAN-ALBERTA (PA 79-2) FORECAST, THE PAN-ALBERTA (PA 80-3) FORECAST LESS PAN-ALBERTA'S SALES TO WESTCOAST AND GAZ METRO, AND THE WESTCOAST GL-41 ALBERTA SUPPLY AFTER 1989. THE SUPPLY HAS BEEN ADJUSTED TO ACCOUNT FOR THE 1980 RESERVES REVISION REFERRED TO IN TABLE SD-4.

-COLUMN 3 IS THE BOARD'S ESTIMATE OF TCPL'S ALBERTA SALES AND THE AGTL FUEL AND REPROCESSING SHRINKAGES ASSOCIATED WITH TCPL'S SUPPLY (COLUMNS 3 AND 4, TABLE SD-7).

-COLUMN 4 IS THE SUPPLY FROM DEFERRED RESERVES IN ALBERTA ADOPTED FROM TRANSCANADA'S SUBMISSION TO THE INQUIRY.

-COLUMN 5 IS THE BOARD'S ESTIMATE OF SUPPLY FROM UNCOMMITTED GAS RESERVES IN ALBERTA.

-COLUMN 6 IS THE BOARD'S ESTIMATE OF SUPPLY FROM 1/2 OF THE RESERVES BEYOND ECONOMIC REACH IN ALBERTA.

-COLUMN 7 DOES NOT INCLUDE A FORECAST OF SUPPLY FROM ALBERTA FUTURE RESERVES ADDITIONS SINCE THIS CURRENT DELIVERABILITY TEST DOES NOT INCLUDE RESERVES ADDITIONS.

-COLUMN 9 IS THE QUANTITY OF GAS SUPPLY IN EXCESS OF ALBERTA'S TOTAL REQUIREMENTS.

TABLE SD-6

ADDITIONAL GAS SUPPLY NECESSARY TO MEET BRITISH COLUMBIA TOTAL DEMAND

(PETAJOULES/YEAR)

YEAR	(1) TOTAL DEMAND	(2) WESTCOAST SUPPLY	(3) PAN ALTA SUPPLY	(4) COLUMBIA SUPPLY	(5) A+S SALES COLUMBIA	(6) UNCOMMITTED BC SUPPLY	(7) BC TREND	(8) NET BC SUPPLY (2+3+4+5+6+7)	(9) DEMAND FOR ALTA GAS (1-8)
1981	539	483	35	14	6	0	0	538	1
1982	558	501	35	14	7	0	0	557	1
1983	577	491	35	14	8	0	0	547	29
1984	583	492	42	14	8	4	0	561	22
1985	592	489	42	14	9	8	0	563	29
1986	594	465	42	14	10	12	0	544	50
1987	596	428	50	14	10	17	0	518	78
1988	599	402	50	14	11	21	0	497	101
1989	549	367	50	14	11	24	0	465	84
1990	274	254	0	14	11	25	0	304	-30
1991	281	261	0	14	11	26	0	311	-30
1992	290	267	0	6	11	26	0	311	-21
1993	298	239	0	1	11	26	0	277	20
1994	316	225	0	0	11	25	0	261	55
1995	345	204	0	0	11	25	0	239	105
1996	359	176	0	0	11	23	0	210	149
1997	370	165	0	0	11	22	0	197	173
1998	385	152	0	0	11	20	0	183	202
1999	399	140	0	0	11	19	0	169	230
2000	412	127	0	0	11	17	0	155	257
TOTAL	8913	6328	380	163	200	339	0	7410	1503

-COLUMN 1 IS THE TOTAL BRITISH COLUMBIA DEMAND OBTAINED BY ADDING THE TOTAL DOMESTIC AND EXPORT DEMANDS, COLUMNS 7 AND 8 FROM TABLE SD-2.

-COLUMN 2 IS THE NEB FORECAST OF WESTCOAST GL-41 GAS SUPPLY FROM COLUMN 3, TABLE SD-4 AND EXCLUDES THE QUANTITIES FROM ITS ALBERTA PERMIT FIELDS AFTER THE PERMITS EXPIRE IN 1989.

-COLUMN 3 IS PAN-ALBERTA'S ESTIMATE OF ITS (PA 80-3 PERMIT) SALES TO WESTCOAST.

-COLUMN 4 IS THE BOARD'S FORECAST OF COLUMBIA'S KOTANEELEE SUPPLY FROM COLUMN 8, TABLE SD-4.

-COLUMN 5 IS A+S'S ESTIMATE OF ITS SALES TO COLUMBIA NATURAL GAS IN BRITISH COLUMBIA.

-COLUMN 6 IS THE BOARD'S FORECAST OF SUPPLY FROM UNCOMMITTED RESERVES (I.E. THE 1980 RESERVES ADDITION) IN BRITISH COLUMBIA.

-COLUMN 7 DOES NOT INCLUDE A FORECAST OF SUPPLY FROM BRITISH COLUMBIA FUTURE RESERVES ADDITIONS SINCE THIS CURRENT DELIVERABILITY TEST DOES NOT INCLUDE RESERVES ADDITIONS.

-COLUMN 9 IS THE ADDITIONAL GAS SUPPLY NECESSARY TO MEET BRITISH COLUMBIA TOTAL DEMAND.

TABLE SD-7

ADDITIONAL GAS SUPPLY NECESSARY TO MEET TOTAL DEMAND EAST OF ALBERTA

(PETAJOULES/YEAR)

YEAR	(1) TOTAL DEMAND	(2) TCPL SUPPLY	(3) TCPL ALTA SALES	(4) AGTL FUEL	(5) MIP SUPPLY	(6) SULPETRO SUPPLY	(7) PROGAS SUPPLY	(8) PAN ALTA SUPPLY	(9) PROD EAST ALTA	(10) SASK TREND	(11) NET SUPPLY (2-3-4+5+6 +7+8+9+10)	(12) DEMAND FOR ALTA GAS (1-11)
1981	1696	1768	42	117	19	27	79	15	59	0	1808	-112
1982	1660	1783	42	118	18	25	96	15	64	0	1841	-181
1983	1687	1786	42	118	20	24	103	15	60	0	1848	-160
1984	1742	1848	42	122	22	23	102	15	64	0	1909	-167
1985	1743	1778	42	117	22	22	99	15	63	0	1840	-97
1986	1678	1732	42	114	20	21	94	15	60	0	1785	-107
1987	1664	1616	42	106	18	21	86	15	57	0	1663	1
1988	1662	1506	42	99	16	20	78	15	53	0	1546	116
1989	1700	1402	42	92	15	20	70	15	50	0	1437	263
1990	1676	1282	42	83	13	20	63	0	46	0	1298	378
1991	1607	1139	42	74	11	17	56	0	44	0	1152	455
1992	1590	1031	42	66	10	14	50	0	41	0	1038	553
1993	1621	941	42	60	9	12	45	0	39	0	945	676
1994	1663	819	42	52	8	11	40	0	36	0	820	843
1995	1703	701	42	44	7	10	35	0	35	0	702	1002
1996	1730	612	42	38	6	9	31	0	32	0	610	1121
1997	1770	513	42	32	6	8	28	0	30	0	512	1258
1998	1822	428	42	26	5	8	20	0	28	0	421	1401
1999	1884	352	42	21	4	7	18	0	25	0	344	1540
2000	1951	305	42	18	4	6	16	0	23	0	294	1657
TOTAL	34250	23343	840	1517	253	322	1207	135	908	0	23811	10439

-COLUMN 1 IS THE TOTAL DEMAND FOR GAS EAST OF ALBERTA FROM COLUMNS 9 AND 10, TABLE SD-2.

-COLUMN 2 IS THE NEB FORECAST OF SUPPLY FROM TCPL'S CONTRACTED GAS QUANTITIES (COLUMN 1, TABLE SD-4). THIS FORECAST WAS BASED ON THE BOARD'S ESTIMATE OF TCPL'S REQUIREMENTS PLUS ANY FORECAST DEFICIENCIES IN THE OTHER SYSTEMS.

-COLUMN 3 IS THE BOARD'S ESTIMATE OF TCPL'S SALES TO ALBERTA UTILITIES.

-COLUMN 4 IS THE NEB ESTIMATE OF EMPRESS SHRINKAGE AND AGTL FUEL REQUIRED TO TRANSPORT TCPL'S GAS FOR EAST OF ALBERTA USE. THE QUANTITIES ARE BASED ON TCPL THROUGHPUT.

-COLUMN 5 IS THE MANY ISLANDS PIPELINES' FORECAST OF PRODUCTION FROM COLUMN 12, TABLE SD-4.

-COLUMN 6 IS THE NEB FORECAST OF SULPETRO GAS SUPPLY, FROM COLUMN 6, TABLE SD-4.

-COLUMN 7 IS THE NEB FORECAST OF PROGAS GAS SUPPLY FROM COLUMN 7, TABLE SD-4.

-COLUMN 8 IS THE PAN-ALBERTA ESTIMATE OF ITS SALES TO GAZ METRO FROM ITS AERCB PA 80-3 PERMIT FIELDS.

-COLUMN 9 IS THE FORECAST OF PRODUCTION EAST OF ALBERTA (COLUMN 13, TABLE SD-4).

-COLUMN 10 DOES NOT INCLUDE A FORECAST OF SUPPLY FROM SASKATCHEWAN FUTURE RESERVES ADDITIONS SINCE THIS CURRENT DELIVERABILITY TEST DOES NOT INCLUDE RESERVES ADDITIONS.

-COLUMN 12 IS THE ADDITIONAL GAS SUPPLY NECESSARY TO MEET TOTAL DEMAND EAST OF ALBERTA.

TABLE SD-8

ALLOCATION OF GAS SURPLUS TO ALBERTA DEMAND

(PETAJOULES/YEAR)

	SURPLUS SUPPLIES			DEMAND FOR ALTA SURPLUS		ALLOCATION OF SURPLUS		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
YEAR	ALBERTA SURPLUS	SUPPLY FROM TEMP SURPLUS	TOTAL	EAST OF ALBERTA	BRITISH COLUMBIA	EAST OF ALBERTA	BRITISH COLUMBIA	TEMP SURPLUS FOR LATER
1981	-14	0	98	-112	1	0	1	97
1982	-59	0	122	-181	1	0	1	121
1983	-6	0	154	-160	29	0	29	125
1984	-137	0	30	-167	22	0	22	8
1985	-199	18	-83	-97	29	0	-83	0
1986	-110	18	15	-107	50	0	15	0
1987	139	0	139	1	78	1	78	61
1988	333	0	333	116	101	116	101	116
1989	239	28	266	263	84	202	64	0
1990	318	28	376	378	-30	376	0	0
1991	224	28	282	455	-30	282	0	0
1992	141	28	190	553	-21	190	0	0
1993	17	25	42	676	20	41	1	0
1994	-119	23	-95	843	55	-89	-6	0
1995	-146	21	-124	1002	105	-112	-12	0
1996	-224	20	-204	1121	149	-180	-24	0
1997	-260	18	-242	1258	173	-213	-29	0
1998	-355	16	-338	1401	202	-296	-43	0
1999	-452	15	-437	1540	230	-380	-57	0
2000	-527	14	-513	1657	257	-444	-69	0
TOTAL	-1193	300	12	10439	1503	-507	-9	529

-COLUMN 1 IS THE TOTAL PROJECTED SUPPLY OF GAS SURPLUS TO ALBERTA'S REQUIREMENTS FROM COLUMN 9, TABLE SD-5.

-GAS WAS ASSUMED TO FLOW EITHER EAST OR WEST TO MEET DEFICIENCIES AS REQUIRED.

-AFTER SUPPLYING BRITISH COLUMBIA AND EAST OF ALBERTA AS SHOWN IN COLUMNS 6 AND 7, THERE REMAIN QUANTITIES OF GAS WHICH PROVIDE A TEMPORARY OVERALL SURPLUS TO TOTAL DEMAND. THESE QUANTITIES, SHOWN IN COLUMN 8, ARE ASSUMED NOT TO BE PRODUCED AND ARE CONVERTED TO A FORECAST OF DELIVERABILITY SHOWN IN COLUMN 2. THEY ARE PRODUCED AT A RATE OF 1:7000 FOR EIGHT YEARS AND DECLINED THEREAFTER AT 8.22 PERCENT PER YEAR.

-THE TOTAL SURPLUS SUPPLY, COLUMN 3, IS ALLOCATED BETWEEN BRITISH COLUMBIA AND EAST OF ALBERTA BASED UPON THE PROPORTION OF THE UNSATISFIED DEMAND WHICH IS ATTRIBUTABLE TO EACH OF THESE REGIONS.

TABLE SD-9

ADJUSTMENTS TO ALBERTA UNCOMMITTED AND TREND SUPPLIES

(PETAJOULES/YEAR)

			UNADJUSTED		ADJUSTED	
	(1)	(2)	(3)	(4)	(5)	(6)
YEAR	TEMPORARY SURPLUS SUPPLY	DEFERRED DELIVERABILITY	ALBERTA UNCOMMITTED	ALBERTA TREND	ALBERTA UNCOMMITTED	ALBERTA TREND
1981	97	0	199	0	101	0
1982	121	0	279	0	158	0
1983	125	0	360	0	236	0
1984	8	0	441	0	433	0
1985	0	18	521	0	539	0
1986	0	18	574	0	592	0
1987	61	0	600	0	539	0
1988	116	0	612	0	495	0
1989	0	28	616	0	644	0
1990	0	28	609	0	637	0
1991	0	28	575	0	603	0
1992	0	28	544	0	572	0
1993	0	25	514	0	539	0
1994	0	23	477	0	500	0
1995	0	21	446	0	467	0
1996	0	20	414	0	434	0
1997	0	18	383	0	401	0
1998	0	16	350	0	367	0
1999	0	15	321	0	336	0
2000	0	14	296	0	310	0
TOTAL	529	300	9131	0	8903	0

-COLUMN 1 IS THE TEMPORARY SURPLUS ALBERTA SUPPLY TAKEN FROM COLUMN 8, TABLE SD-8.

-COLUMN 2 IS THE DELIVERABILITY ATTRIBUTABLE TO THE QUANTITIES INDICATED TO BE SURPLUS IN COLUMN 1 AND ASSUMED NOT TO BE PRODUCED IN THE PERIOD INDICATED IN COLUMN 1.

-THE FIGURES IN COLUMNS 1 AND 2 WERE USED TO ADJUST THE NEB FORECAST OF SUPPLY FROM UNCOMMITTED ALBERTA GAS, COLUMN 3, WHICH IS THE SUM OF COLUMNS 5 AND 6, TABLE SD-5.

-NO ADJUSTMENTS WERE REQUIRED FOR TREND GAS AS THIS CURRENT DELIVERABILITY TEST DOES NOT CONSIDER FUTURE RESERVES ADDITIONS.

-THE ADJUSTED FORECAST OF UNCOMMITTED ALBERTA RESERVES IS SHOWN IN COLUMN 5.

TABLE SD-10

BRITISH COLUMBIA SUPPLY/DEMAND BALANCE

(PETAJOULES/YEAR)

YEAR	DEMAND (1) B.C. DEMAND	(2) HUNTINGTON EXPORT	(3) TOTAL	SUPPLY (4) B.C. NET SUPPLY	(5) ALTA SURPLUS TO B.C.	(6) TOTAL (4+5)	(7) DEFICIENCY (3-6)
1981	195	344	539	538	1	539	0
1982	214	344	558	557	1	558	0
1983	233	344	577	547	29	577	0
1984	239	344	583	561	22	583	0
1985	251	341	592	563	-83	480	112
1986	257	337	594	544	15	559	35
1987	263	333	596	518	78	596	0
1988	269	330	599	497	101	599	0
1989	274	275	549	465	64	529	19
1990	274	0	274	304	0	304	-30
1991	281	0	281	311	0	311	-30
1992	290	0	290	311	0	311	-21
1993	298	0	298	277	1	279	19
1994	316	0	316	261	-6	255	61
1995	345	0	345	239	-12	228	117
1996	359	0	359	210	-24	186	173
1997	370	0	370	197	-29	168	202
1998	385	0	385	183	-43	141	244
1999	399	0	399	169	-57	112	286
2000	412	0	412	155	-69	86	326
TOTAL	5921	2992	8913	7410	-9	7401	1512

-COLUMN 1 IS TAKEN FROM COLUMN 7, TABLE SD-2.

-COLUMN 2 IS TAKEN FROM COLUMN 8, TABLE SD-2.

-COLUMN 4 IS TAKEN FROM COLUMN 8, TABLE SD-6.

-COLUMN 5 IS TAKEN FROM COLUMN 7, TABLE SD-8.

TABLE SD-11

EAST OF ALBERTA SUPPLY/DEMAND BALANCE

(PETAJOULES/YEAR)

	DEMAND			SUPPLY			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
YEAR	CANADIAN	EXPORT	TOTAL	NET SUPPLY EAST OF ALTA	ALTA SURPLUS TO EAST OF ALTA	TOTAL (4+5)	DEFICIENCY (3-6)
1981	1085	611	1696	1808	0	1808	-112
1982	1125	535	1660	1841	0	1841	-181
1983	1171	516	1687	1848	0	1848	-160
1984	1237	505	1742	1909	0	1909	-167
1985	1309	434	1743	1840	0	1840	-97
1986	1349	329	1678	1785	0	1785	-107
1987	1388	276	1664	1663	1	1664	0
1988	1428	234	1662	1546	116	1662	0
1989	1478	222	1700	1437	202	1639	61
1990	1526	150	1676	1298	376	1674	2
1991	1548	59	1607	1152	282	1434	173
1992	1577	14	1590	1038	190	1228	363
1993	1607	14	1621	945	41	986	635
1994	1649	14	1663	820	-89	730	933
1995	1692	11	1703	702	-112	589	1114
1996	1730	0	1730	610	-180	429	1301
1997	1770	0	1770	512	-213	298	1471
1998	1822	0	1822	421	-296	125	1697
1999	1884	0	1884	344	-380	-36	1920
2000	1951	0	1951	294	-444	-150	2101
TOTAL	30327	3923	34250	23811	-507	23304	10946

-COLUMN 1 IS TAKEN FROM COLUMN 9, TABLE SD-2.

-COLUMN 2 IS TAKEN FROM COLUMN 10, TABLE SD-2.

-COLUMN 4 IS TAKEN FROM COLUMN 11, TABLE SD-7.

-COLUMN 5 IS TAKEN FROM COLUMN 6, TABLE SD-8.

TABLE SD-12

FORECAST OF REPROCESSING PLANT SHRINKAGES AND FUEL

(PETAJOULES/YEAR)

	COCHRANE				EMPRESS				EDMONTON				
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
YEAR	ETHANE	NGL	FUEL	TOTAL (1+2+3)	ETHANE	NGL	FUEL	TOTAL (5+6+7)	ETHANE	NGL	FUEL	TOTAL (9+10+11)	TOTAL (4+8+12)
1981	29	17	5	50	47	55	13	115	14	14	0	28	193
1982	29	16	5	50	47	55	8	110	23	16	0	40	200
1983	36	16	3	55	47	55	8	110	24	16	0	41	205
1984	43	15	3	61	69	68	15	152	21	15	0	37	249
1985	41	14	3	58	84	68	15	166	20	15	0	35	260
1986	38	13	3	54	84	68	15	166	22	18	0	40	261
1987	36	12	3	51	84	68	15	166	21	18	0	39	256
1988	27	9	3	39	80	65	14	159	20	18	0	38	236
1989	24	8	2	35	79	64	14	156	13	8	0	21	212
1990	23	8	2	33	81	65	14	161	12	8	0	20	213
1991	21	7	2	30	68	55	12	135	11	7	0	19	184
1992	19	7	2	28	57	46	10	113	11	7	0	18	159
1993	17	6	2	25	44	35	8	87	10	7	0	18	130
1994	15	5	1	22	30	24	5	60	10	7	0	17	99
1995	11	4	1	16	23	18	4	45	8	8	0	17	78
1996	10	3	1	14	14	11	2	28	8	8	0	17	58
1997	9	3	1	12	7	6	1	14	8	8	0	16	43
1998	8	3	1	11	0	0	0	0	8	8	0	16	27
1999	6	2	1	9	0	0	0	0	8	8	0	16	25
2000	6	2	1	8	0	0	0	0	8	8	0	16	24
TOTAL	449	170	43	662	944	827	172	1942	278	222	8	508	3112

-THIS TABLE REPRESENTS THE BOARD'S FORECASTS OF REPROCESSING PLANT SHRINKAGES AND FUEL BASED ON THE THROUGHPUTS PROJECTED IN THIS SUPPLY-DEMAND BALANCE.

-THE BOARD'S FORECAST OF SHRINKAGE AND FUEL AT COCHRANE BASED ON PROJECTED THROUGHPUT IS SHOWN IN COLUMNS 1, 2 AND3.

-THE BOARD'S FORECAST OF SHRINKAGE AND FUEL AT EMPRESS BASED ON PROJECTED THROUGHPUT IS SHOWN IN COLUMNS 5, 6 AND 7.

-THE FORECAST OF SHRINKAGE AND FUEL AT EDMONTON BASED ON DOME'S SUBMISSION IS SHOWN IN COLUMNS 9, 10 AND 11.

TABLE SD-13

TOTAL CANADIAN SUPPLY/DEMAND BALANCE

(PETAJOULES/YEAR)

	DEMAND			SUPPLY						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
YEAR	DOMESTIC	EXPORT	TOTAL	TOTAL CONTROLLED	ALBERTA UNCOMMITTED	B C UNCOMMITTED	ALTA DEFERRED	TREND SUPPLY	TOTAL (4+5+6+7+8)	DEFICIENCY (3-9)
REMAINING RESERVES AT 31 DECEMBER 1980				59201	13441	530	3066	0	76238	
1981	2076	1675	3751	3646	101	0	3	0	3751	0
1982	2157	1863	4020	3859	158	0	3	0	4020	0
1983	2304	1845	4150	3911	236	0	3	0	4150	0
1984	2455	1843	4298	3857	433	4	4	0	4298	0
1985	2572	1736	4308	3643	539	8	6	0	4196	112
1986	2633	1484	4117	3471	592	12	6	0	4082	35
1987	2691	1083	3773	3211	539	17	6	0	3773	0
1988	2750	751	3501	2973	495	21	12	0	3501	0
1989	2855	642	3498	2723	644	24	27	0	3417	80
1990	2874	244	3118	2412	637	25	42	0	3116	2
1991	2897	145	3043	2203	603	26	39	0	2870	173
1992	2943	62	3005	2010	572	26	35	0	2642	363
1993	2989	54	3043	1791	539	26	32	0	2388	654
1994	3062	14	3075	1528	500	25	28	0	2082	994
1995	3143	11	3155	1386	467	25	46	0	1924	1231
1996	3214	0	3214	1238	434	23	45	0	1740	1474
1997	3281	0	3281	1086	401	22	100	0	1608	1673
1998	3374	0	3374	948	367	20	97	0	1432	1941
1999	3475	0	3475	820	336	19	95	0	1269	2206
2000	3585	0	3585	719	310	17	112	0	1158	2427
TOTAL	57330	13452	70782	47437	8903	339	740	0	57418	13364

-FIGURES MAY NOT ADD DUE TO ROUNDING.

-BOARD ESTIMATES OF THE REMAINING MARKETABLE RESERVES AT 31 DECEMBER, 1980 WHICH SUPPORT THE NEB FORECASTS OF SUPPLY ARE SHOWN AT THE TOP OF COLUMNS 4 TO 9.

-COLUMN 5 INCLUDES THE UNCOMMITTED ALBERTA RESERVES AT 31 DECEMBER, 1979, THE TOTAL RESERVES BEYOND ECONOMIC REACH IN ALBERTA AND THE 1980 ALBERTA RESERVES ADDITION.

-COLUMN 6 IS THE SUPPLY FORECAST FROM THE 1980 RESERVES ADDITION IN BRITISH COLUMBIA.

-COLUMNS 1 TO 7 INCLUSIVE ARE TAKEN FROM COLUMNS 11, 12 AND 13, TABLE SD-2; COLUMN 14, TABLE SD-4; COLUMN 5, TABLE SD-9; COLUMN 6, TABLE SD-6 AND COLUMN 4, TABLE SD-5.

-THE TOTAL DEFICIENCY IN COLUMN 10 INCLUDES THE POSITIVE DEFICIENCIES FOR BRITISH COLUMBIA AND EAST OF ALBERTA FROM COLUMN 7, TABLE SD-10 AND COLUMN 7, TABLE SD-11 RESPECTIVELY.

NATURAL GAS SUPPLY/DEMAND BALANCE UNDER THE FUTURE DELIVERABILITY TEST

Tables SD-1 to SD-13, following, illustrate the detailed supply/demand balancing procedure used in the verification of the Board's Future Deliverability Test for the Base Case Supply and Middle Case Demand Scenario.

The total Canada natural gas balance is shown in Table SD-13.

TABLE SD-1

TOTAL DEMAND FOR CANADIAN NATURAL GAS

(PETAJOULES/YEAR)

	DOMESTIC					EXPORT			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
YEAR	NET SALES	DOMESTIC FUEL	NET REPROC	FUEL FOR EXPORTS	TOTAL DOMESTIC (1+2+3+4)	EXISTING EXPORTS	NEW EXPORTS	FUEL NEW EXPORTS	TOTAL DEMAND (5+6+7+8)
1981	1752	75	193	55	2076	1675	0	0	3751
1982	1821	79	200	57	2157	1863	0	0	4020
1983	1959	84	205	55	2304	1845	0	0	4150
1984	2062	89	249	55	2455	1843	0	0	4298
1985	2167	95	260	51	2573	1743	0	0	4316
1986	2231	99	265	44	2638	1550	0	0	4188
1987	2300	102	260	38	2699	1317	0	0	4017
1988	2385	105	252	32	2774	1100	0	0	3874
1989	2506	110	219	21	2855	642	0	0	3498
1990	2538	114	213	9	2874	244	0	0	3118
1991	2574	116	203	5	2897	145	0	0	3043
1992	2624	118	198	2	2943	62	0	0	3005
1993	2668	121	198	2	2989	54	0	0	3043
1994	2737	124	200	1	3062	14	0	0	3075
1995	2816	129	198	1	3143	11	0	0	3155
1996	2885	132	197	0	3214	0	0	0	3214
1997	2951	135	195	0	3281	0	0	0	3281
1998	3041	139	194	0	3374	0	0	0	3374
1999	3140	143	192	0	3475	0	0	0	3475
2000	3246	148	190	0	3585	0	0	0	3585
TOTAL	50406	2257	4280	424	57368	14109	0	0	71477

-FIGURES MAY NOT ADD DUE TO ROUNDING.

-COLUMN 1 IS THE TOTAL DOMESTIC NET SALES IN CANADA.

-COLUMN 2 IS THE FUEL FOR THE DOMESTIC NET SALES.

-COLUMN 3 IS THE TOTAL REPROCESSING SHRINKAGE REQUIREMENTS FROM COLUMN 13, TABLE SD-3.

-COLUMN 4 IS THE FUEL FOR THE EXISTING FIRM PLUS EXTENDED LICENCES.

-COLUMN 6 IS THE EXISTING FIRM PLUS EXTENDED LICENCES NOT INCLUDING FUEL.

-COLUMN 7 REPRESENTS THE POSSIBLE NEW EXPORTS CONSIDERED IN THIS TEST.

-COLUMN 8 IS THE INCREMENTAL FUEL FOR THE NEW EXPORTS.

TABLE SD-2

DEMAND FOR CANADIAN GAS BY AREAS

(PETAJOULES/YEAR)

	ALBERTA						BRITISH COLUMBIA		EAST OF ALBERTA		TOTAL CANADA		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
YEAR	DOMESTIC	EXPORT	AGTL FUEL	NET REPROC	ANG FUEL	EAST LEG FUEL	DOMESTIC	EXPORT	DOMESTIC	EXPORT	DOMESTIC (1+3+4+5+6+7+9)	EXPORT (2+8+10)	TOTAL (11+12)
1981	574	720	21	193	7	1	195	344	1085	611	2076	1675	3751
1982	584	984	23	200	7	3	214	344	1125	535	2157	1863	4020
1983	661	985	23	205	7	3	233	344	1171	516	2304	1845	4150
1984	696	993	23	249	7	3	239	344	1237	505	2455	1843	4298
1985	720	968	23	260	7	3	251	341	1309	434	2573	1743	4316
1986	737	884	21	265	6	3	257	337	1349	329	2638	1550	4188
1987	763	708	18	260	4	3	263	333	1388	276	2699	1317	4017
1988	804	537	16	252	3	3	269	330	1428	234	2774	1100	3874
1989	872	146	11	219	2	0	274	275	1478	222	2855	642	3498
1990	849	94	10	213	1	0	274	0	1526	150	2874	244	3118
1991	856	86	9	203	1	0	281	0	1548	59	2897	145	3043
1992	869	49	8	198	1	0	290	0	1577	14	2943	62	3005
1993	877	40	8	198	0	0	298	0	1607	14	2989	54	3043
1994	888	0	8	200	0	0	316	0	1649	14	3062	14	3075
1995	900	0	8	198	0	0	345	0	1692	11	3143	11	3155
1996	919	0	9	197	0	0	359	0	1730	0	3214	0	3214
1997	938	0	9	195	0	0	370	0	1770	0	3281	0	3281
1998	963	0	9	194	0	0	385	0	1822	0	3374	0	3374
1999	992	0	9	192	0	0	399	0	1884	0	3475	0	3475
2000	1022	0	10	190	0	0	412	0	1951	0	3585	0	3585
TOTAL	16485	7194	276	4280	55	23	5921	2992	30327	3923	57368	14109	71477

-FIGURES MAY NOT ADD DUE TO ROUNDING.

-COLUMNS 1 PLUS 3 REPRESENT THE TOTAL DOMESTIC DEMAND FOR GAS IN ALBERTA. COLUMN 1 INCLUDES THE FUEL AND LOSSES FOR DISTRIBUTION OF ALBERTA'S NET SALES OF GAS. COLUMN 3 IS THE FUEL REQUIREMENTS FOR AGTL FOR ALL GAS TRANSPORTED IN ITS SYSTEM LEAVING THE PROVINCE.

-COLUMN 2 IS THE TOTAL EXPORTS SOUTH FROM ALBERTA - ALBERTA AND SOUTHERN, WESTCOAST GL-4 AND PAN-ALBERTA WEST VIA KINGSGATE, BRITISH COLUMBIA; CANADIAN-MONTANA VIA CARDSTON AND ADEN, ALBERTA; AND PAN-ALBERTA EAST VIA MONCHY, SASK.

-COLUMN 4 IS THE TOTAL REPROCESSING SHRINKAGE REQUIREMENTS FROM COLUMN 13, TABLE SD-3.

-COLUMNS 5 AND 6 REPRESENT THE FUEL REQUIRED TO TRANSPORT THE EXPORTS ON THE ANG SYSTEM TO KINGSGATE AND THE PRE-BUILD EAST LEG TO MONCHY RESPECTIVELY.

-COLUMNS 7 AND 9 ARE THE CANADIAN REQUIREMENTS EXCLUDING ALBERTA. THEY INCLUDE FUEL AND LOSSES ASSOCIATED WITH TRANSMISSION AND DISTRIBUTION OUTSIDE ALBERTA .

-COLUMN 8 IS THE WESTCOAST GL-41 EXISTING EXPORTS PLUS THE COLUMBIA EXPORTS.

-COLUMN 10 IS THE TOTAL EXPORTS EAST OF ALBERTA - TCPL, ICG, NIAGARA, SULPETRO, CONSOLIDATED AND PROGAS.

-THE EXISTING EXPORTS IN COLUMNS 2, 8 AND 10 HAVE BEEN GIVEN THE FULL PROTECTION ALLOWED IN THE LICENCES.

TABLE SD-3

REPROCESSING PLANT SHRINKAGE AND FUEL
REQUIREMENTS
(PETAJOULES/YEAR)

YEAR	COCHRANE (1) ETHANE	(2) NGL	(3) FUEL	(4) TOTAL (1+2+3)	EMPRESS (5) ETHANE	(6) NGL	(7) FUEL	(8) TOTAL (5+6+7)	EDMONTON (9) ETHANE	(10) NGL	(11) FUEL	(12) TOTAL (9+10+11)	(13) TOTAL (4+8+12)
1981	29	17	5	50	47	55	13	115	14	14	0	28	193
1982	29	16	5	50	47	55	8	110	23	16	0	40	200
1983	36	16	3	55	47	55	8	110	24	16	0	41	205
1984	43	15	3	61	69	68	15	152	21	15	0	37	249
1985	42	14	3	59	84	68	15	166	20	15	0	35	260
1986	41	14	3	58	84	68	15	166	22	18	0	40	265
1987	38	13	3	54	84	68	15	166	21	18	0	39	260
1988	33	11	3	47	84	68	15	166	20	18	0	38	252
1989	24	8	2	35	82	66	14	163	13	8	0	21	219
1990	23	8	2	33	81	66	14	161	12	8	0	20	213
1991	21	7	2	30	77	63	14	154	11	7	0	19	203
1992	19	7	2	28	77	62	14	152	11	7	0	18	198
1993	17	6	2	25	78	63	14	156	10	7	0	18	198
1994	15	5	1	22	81	65	14	161	10	7	0	17	200
1995	11	4	1	16	83	67	15	165	8	8	0	17	198
1996	10	3	1	14	84	68	15	166	8	8	0	17	197
1997	9	3	1	12	84	68	15	166	8	8	0	16	195
1998	8	3	1	11	84	68	15	166	8	8	0	16	194
1999	6	2	1	9	84	68	15	166	8	8	0	16	192
2000	6	2	1	8	84	68	15	166	8	8	0	16	190
TOTAL	460	174	44	677	1524	1296	275	3095	278	222	8	508	4280

-THIS TABLE REPRESENTS THE BOARD'S FORECASTS OF EXPECTED REQUIREMENTS FOR REPROCESSING PLANT SHRINKAGES AND FUEL AT COCHRANE, EMPRESS AND EDMONTON.

-THE BOARD'S FORECAST OF SHRINKAGE AND FUEL AT COCHRANE, COLUMNS 1, 2 AND 3, IS BASED ON ITS ESTIMATE OF THE MAXIMUM THROUGHPUT AVAILABLE TO COCHRANE THROUGHOUT THE FORECAST PERIOD.

-THE BOARD'S FORECAST OF SHRINKAGE AND FUEL AT EMPRESS, COLUMNS 5, 6 AND 7, IS BASED ON THE TOTAL THROUGHPUT NECESSARY TO MEET REQUIREMENTS EAST OF ALBERTA FROM ALBERTA SUPPLIES THROUGHOUT THE FORECAST PERIOD.

-THE FORECAST OF SHRINKAGE AND FUEL AT EDMONTON, COLUMNS 9, 10 AND 11, IS BASED ON DOME'S SUBMISSION TO THE INQUIRY.

TABLE SD-4

CANADIAN GAS DELIVERABILITY FROM CONTROLLED RESERVES

(PETAJOULES/YEAR)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
YEAR	TCPL	A+S	WTCL GL41	WTCL GL 4	PAN ALTA	SULPETRO SUPPLY	PROGAS SUPPLY	COLUMB SUPPLY	PAN ALTA NEW GAS	ALTA UTIL	CAN MONTANA	MIP	PROD EAST ALTA	TOTAL
REMAINING RESERVES AT 31 DECEMBER 1980	26645	7333	8235	189	1225	420	1337	163	5235	6149	251	613	1406	59201
1981	1768	586	483	41	106	27	79	14	116	366	11	19	59	3646
1982	1783	579	501	34	93	25	96	14	333	354	11	18	64	3859
1983	1786	558	491	29	81	24	103	14	436	342	11	20	60	3911
1984	1848	527	492	24	71	23	102	14	394	318	11	22	64	3857
1985	1778	494	489	13	62	22	99	14	356	286	11	22	63	3643
1986	1732	495	465	4	54	21	94	14	313	261	10	20	60	3471
1987	1616	454	428	4	48	21	86	14	274	234	10	18	57	3211
1988	1506	410	402	4	41	20	78	14	245	220	11	16	53	2973
1989	1402	371	367	4	36	20	70	14	217	201	10	15	50	2723
1990	1282	347	263	4	32	20	63	14	184	186	9	13	46	2412
1991	1139	320	270	4	27	17	56	14	161	174	8	11	44	2203
1992	1031	295	279	4	24	14	50	6	144	162	7	10	41	2010
1993	941	263	251	4	21	12	45	1	131	142	6	9	39	1791
1994	819	233	234	4	19	11	40	0	121	132	6	8	36	1528
1995	701	169	212	4	16	10	35	0	111	123	5	7	35	1386
1996	612	143	184	4	14	9	31	0	101	108	4	6	32	1238
1997	513	128	171	4	13	8	28	0	92	98	4	6	30	1086
1998	428	115	159	3	11	8	20	0	84	89	4	5	28	948
1999	352	99	145	0	10	7	18	0	77	81	4	4	25	820
2000	305	85	132	0	8	6	16	0	72	71	4	4	23	719
TOTAL	23343	6670	6418	189	785	322	1207	163	3961	3947	154	253	908	47437

-FIGURES DO NOT ADD BECAUSE THE EFFECT OF THE 1980 RESERVES REVISION, DESCRIBED IN THE SUPPLY CHAPTER, HAS BEEN CONSIDERED.

-NEB FORECASTS OF PRODUCTION FROM CONTRACTED RESERVES FOR TCPL (INCLUDING CONSOLIDATED), A+S, WESTCOAST GL-41, WESTCOAST GL-4, SULPETRO, PROGAS, COLUMBIA, PAN-ALBERTA (PERMIT PA 79-2) AND CANADIAN-MONTANA ARE IN COLUMNS 1, 2, 3, 4, 6, 7, 8, 9 AND 11 RESPECTIVELY.

-THE WESTCOAST GL-41 FORECAST INCLUDES ALL GAS IN THE WESTCOAST SUPPLY AREA EXCEPTING 0.5 EJ OF UNCOMMITTED RESERVES (I.E. THE 1980 RESERVES ADDITION).

-COLUMN 5 IS THE FORECAST OF PAN-ALBERTA'S AERCB PERMIT NO. PA 80-3 SUPPLY ADOPTED FROM PAN-ALBERTA.

-COLUMN 10 IS THE FORECAST OF ALBERTA UTILITIES' SUPPLY ADOPTED FROM THE CONSULTANT'S FORECAST FOR THE JOINT APPLICANTS TO HEARING GH-4-79. THIS FORECAST EXCLUDES THE SUPPLY FROM DEFERRED RESERVES CONTROLLED BY THE ALBERTA UTILITIES.

-COLUMN 12 IS THE FORECAST OF MANY ISLANDS PIPELINES' SUPPLY ADOPTED FROM THE SPC SUBMISSION TO THIS GAS INQUIRY.

-COLUMN 13, PRODUCTION EAST OF ALBERTA, INCLUDES THE FORECAST OF SASKATCHEWAN PRODUCTION FROM THE SPC SUBMISSION TO THIS GAS INQUIRY AND THE BOARD'S FORECAST OF ONTARIO PRODUCTION.

-REMAINING RESERVES AT 31 DECEMBER 1980 REPRESENT THE BOARD'S ESTIMATES BASED UPON AVAILABLE INFORMATION REGARDING CONTROLLED SUPPLIES.

TABLE SD-5

GAS SUPPLY AVAILABLE TO MEET ALBERTA DEMAND

(PETAJOULES/YEAR)

YEAR	(1) TOTAL DEMAND	(2) ALBERTA SUPPLIES	(3) TCPL ALTA SUPPLIES	(4) DEFERRED SUPPLY	(5) UNCOMMITTED SUPPLY	(6) SUPPLY FROM BER RESERVES	(7) ALBERTA TREND	(8) TOTAL (2+3+4+5+6+7)	(9) SURPLUS (8-1)
1981	1516	1142	159	3	197	2	18	1519	4
1982	1802	1301	160	3	276	3	58	1801	-1
1983	1885	1356	160	3	355	5	127	2006	121
1984	1973	1228	164	4	434	7	229	2065	92
1985	1981	1089	159	6	512	8	344	2119	137
1986	1917	999	156	6	564	10	454	2189	272
1987	1757	898	148	6	589	12	558	2210	454
1988	1613	809	141	12	598	14	658	2231	618
1989	1249	710	134	27	601	15	751	2238	990
1990	1168	710	125	42	593	17	836	2322	1154
1991	1155	650	116	39	557	18	912	2291	1136
1992	1125	579	108	35	525	19	976	2242	1117
1993	1124	493	102	32	494	20	1028	2169	1045
1994	1096	379	94	28	456	21	1070	2048	952
1995	1107	383	86	46	424	22	1101	2062	955
1996	1124	361	80	45	391	23	1122	2023	899
1997	1142	325	74	100	359	24	1135	2017	875
1998	1166	296	68	97	326	24	1141	1952	786
1999	1193	263	63	95	296	25	1140	1881	688
2000	1221	227	60	112	270	26	1133	1828	606
TOTAL	28314	14197	2357	740	8817	314	14788	41214	12900

-COLUMN 1 IS THE TOTAL ALBERTA DEMAND INCLUDING EXPORTS SOUTH FROM ALBERTA AND IS THE SUM OF COLUMNS 1 TO 6 ON TABLE SD-2.

-COLUMN 2 IS THE SUM OF THE ALBERTA UTILITIES FORECAST, THE A+S FORECAST LESS A+S COLUMBIA SALES, THE WESTCOAST GL-4 FORECAST, THE CANADIAN-MONTANA FORECAST, THE PAN-ALBERTA (PA 79-2) FORECAST, THE PAN-ALBERTA (PA 80-3) FORECAST LESS PAN-ALBERTA'S SALES TO WESTCOAST AND GAZ METRO, AND THE WESTCOAST GL-41 SUPPLY AFTER 1989. THE SUPPLY HAS BEEN ADJUSTED TO ACCOUNT FOR THE 1980 RESERVES REVISION REFERRED TO IN TABLE SD-4.

-COLUMN 3 IS THE BOARD'S ESTIMATE AF TCPL'S ALBERTA SALES AND THE AGTL FUEL AND REPROCESSING SHRINKAGES ASSOCIATED WITH TCPL'S SUPPLY (COLUMNS 3 AND 4, TABLE SD-7).

-COLUMN 4 IS THE SUPPLY FROM DEFERRED RESERVES IN ALBERTA ADOPTED FROM TRANSCANADA'S SUBMISSION TO THE INQUIRY.

-COLUMN 5 IS THE BOARD'S ESTIMATE OF SUPPLY FROM UNCOMMITTED GAS RESERVES IN ALBERTA.

-COLUMN 6 IS THE BOARD'S ESTIMATE OF SUPPLY FROM 1/2 OF THE RESERVES BEYOND ECONOMIC REACH IN ALBERTA.

-COLUMN 7 IS THE BOARD'S FORECAST OF SUPPLY FROM ALBERTA FUTURE RESERVES ADDITIONS.

-COLUMN 9 IS THE QUANTITY OF GAS SUPPLY IN EXCESS OF ALBERTA'S TOTAL REQUIREMENTS.

TABLE SD-6

ADDITIONAL GAS SUPPLY NECESSARY TO MEET BRITISH COLUMBIA TOTAL DEMAND

(PETAJOULES/YEAR)

YEAR	(1) TOTAL DEMAND	(2) WESTCOAST SUPPLY	(3) PAN ALTA SUPPLY	(4) COLUMBIA SUPPLY	(5) A+S SALES COLUMBIA	(6) UNCOMMITTED BC SUPPLY	(7) BC TREND	(8) NET BC SUPPLY (2+3+4+5+6+7)	(9) DEMAND FOR ALTA GAS (1-8)
1981	539	483	35	14	6	0	3	541	-2
1982	558	501	35	14	7	0	9	566	-8
1983	577	491	35	14	8	0	19	566	10
1984	583	492	42	14	8	4	34	595	-12
1985	592	489	42	14	9	8	52	615	-23
1986	594	465	42	14	10	12	69	612	-19
1987	596	428	50	14	10	17	85	603	-7
1988	599	402	50	14	11	21	100	597	1
1989	549	367	50	14	11	24	115	580	-31
1990	274	254	0	14	11	25	128	432	-158
1991	281	261	0	14	11	26	140	451	-170
1992	290	267	0	6	11	26	150	461	-171
1993	298	239	0	1	11	26	159	436	-138
1994	316	225	0	0	11	25	166	427	-110
1995	345	204	0	0	11	25	171	410	-66
1996	359	176	0	0	11	23	175	385	-26
1997	370	165	0	0	11	22	177	374	-5
1998	385	152	0	0	11	20	179	362	23
1999	399	140	0	0	11	19	179	348	51
2000	412	127	0	0	11	17	178	333	78
TOTAL	8913	6328	380	163	200	339	2285	9695	-782

-COLUMN 1 IS THE TOTAL BRITISH COLUMBIA DEMAND OBTAINED BY ADDING THE TOTAL DOMESTIC AND EXPORT DEMANDS, COLUMNS 7 AND 8 FROM TABLE SD-2.

-COLUMN 2 IS THE NEB FORECAST OF WESTCOAST GL-41 GAS SUPPLY FROM COLUMN 3, TABLE SD-4 AND EXCLUDES THE QUANTITIES FROM ITS ALBERTA PERMIT FIELDS AFTER THE PERMITS EXPIRE IN 1989.

-COLUMN 3 IS PAN-ALBERTA'S ESTIMATE OF ITS (PA 80-3) SALES TO WESTCOAST.

-COLUMN 4 IS THE BOARD'S FORECAST OF COLUMBIA'S KOTANEELEE SUPPLY FROM COLUMN 8, TABLE SD-4.

-COLUMN 5 IS A+S'S ESTIMATE OF ITS SALES TO COLUMBIA NATURAL GAS IN BRITISH COLUMBIA.

-COLUMN 6 IS THE BOARD'S FORECAST OF SUPPLY FROM UNCOMMITTED RESERVES (I.E. THE 1980 RESERVES ADDITION) IN BRITISH COLUMBIA.

-COLUMN 7 IS THE BOARD'S FORECAST OF SUPPLY FROM BRITISH COLUMBIA FUTURE RESERVES ADDITIONS.

-COLUMN 9 IS THE ADDITIONAL GAS SUPPLY NECESSARY TO MEET BRITISH COLUMBIA TOTAL DEMAND.

TABLE SD-7

ADDITIONAL GAS SUPPLY NECESSARY TO MEET TOTAL DEMAND EAST OF ALBERTA

(PETAJOULES/YEAR)

YEAR	(1) TOTAL DEMAND	(2) TCPL SUPPLY	(3) TCPL ALTA SALES	(4) AGTL FUEL	(5) MIP SUPPLY	(6) SULPETRO SUPPLY	(7) PROGAS SUPPLY	(8) PAN ALTA SUPPLY	(9) PROD EAST ALTA	(10) SASK TREND	(11) NET SUPPLY (2-3-4+5+6 +7+8+9+10)	(12) DEMAND FOR ALTA GAS (1-11)
1981	1696	1768	42	117	19	27	79	15	59	0	1808	¯112
1982	1660	1783	42	118	18	25	96	15	64	0	1841	¯181
1983	1687	1786	42	118	20	24	103	15	60	1	1849	¯161
1984	1742	1848	42	122	22	23	102	15	64	2	1910	¯168
1985	1743	1778	42	117	22	22	99	15	63	3	1843	¯100
1986	1678	1732	42	114	20	21	94	15	60	4	1789	¯111
1987	1664	1616	42	106	18	21	86	15	57	6	1669	¯5
1988	1662	1506	42	99	16	20	78	15	53	9	1555	107
1989	1700	1402	42	92	15	20	70	15	50	11	1448	252
1990	1676	1282	42	83	13	20	63	0	46	14	1312	364
1991	1607	1139	42	74	11	17	56	0	44	17	1169	438
1992	1590	1031	42	66	10	14	50	0	41	20	1058	533
1993	1621	941	42	60	9	12	45	0	39	23	967	654
1994	1663	819	42	52	8	11	40	0	36	25	845	818
1995	1703	701	42	44	7	10	35	0	35	28	729	974
1996	1730	612	42	38	6	9	31	0	32	30	640	1091
1997	1770	513	42	32	6	8	28	0	30	32	543	1226
1998	1822	428	42	26	5	8	20	0	28	33	453	1369
1999	1884	352	42	21	4	7	18	0	25	33	377	1507
2000	1951	305	42	18	4	6	16	0	23	32	326	1625
TOTAL	34250	23343	840	1517	253	322	1207	135	908	321	24132	10118

-COLUMN 1 IS THE TOTAL DEMAND FOR GAS EAST OF ALBERTA FROM COLUMNS 9 AND 10, TABLE SD-2.

-COLUMN 2 IS THE NEB FORECAST OF SUPPLY FROM TCPL'S CONTRACTED GAS QUANTITIES (COLUMN 1, TABLE SD-4). THIS FORECAST WAS BASED ON THE BOARD'S ESTIMATE OF TCPL'S REQUIREMENTS PLUS ANY FORECAST DEFICIENCIES IN THE OTHER SYSTEMS.

-COLUMN 3 IS THE BOARD'S ESTIMATE OF TCPL'S SALES TO THE ALBERTA UTILITIES.

-COLUMN 4 IS THE NEB ESTIMATE OF EMPRESS SHRINKAGE AND AGTL FUEL REQUIRED TO TRANSPORT TCPL'S GAS FOR EAST OF ALBERTA USE. THE QUANTITIES ARE BASED ON TCPL THROUGHPUT.

-COLUMN 5 IS THE MANY ISLANDS PIPELINES' FORECAST OF PRODUCTION FROM COLUMN 12, TABLE SD-4.

-COLUMN 6 IS THE NEB FORECAST OF SULPETRO GAS SUPPLY FORM COLUMN 6, TABLE SD-4.

-COLUMN 7 IS THE NEB FORECAST OF PROGAS GAS SUPPLY FROM COLUMN 7, TABLE SD-4.

-COLUMN 8 IS THE PAN-ALBERTA ESTIMATE OF ITS SALES TO GAZ METRO FROM ITS AERCB PA 80-3 PERMIT FIELDS.

-COLUMN 9 IS THE FORECAST OF PRODUCTION EAST OF ALBERTA (COLUMN 13, TABLE SD-4).

-COLUMN 10 IS THE BOARD'S FORECAST OF SUPPLY FROM FUTURE RESERVES ADDITIONS IN SASKATCHEWAN.

-COLUMN 12 IS THE ADDITIONAL GAS SUPPLY NECESSARY TO MEET TOTAL DEMAND EAST OF ALBERTA.

TABLE SD-8

ALLOCATION OF GAS SURPLUS TO ALBERTA DEMAND

(PETAJOULES/YEAR)

	SURPLUS SUPPLIES			DEMAND FOR ALTA SURPLUS		ALLOCATION OF SURPLUS		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
YEAR	ALBERTA SURPLUS	SUPPLY FROM TEMP SURPLUS	TOTAL	EAST OF ALBERTA	BRITISH COLUMBIA	EAST OF ALBERTA	BRITISH COLUMBIA	TEMP SURPLUS FOR LATER
1981	4	0	118	-112	-2	0	0	118
1982	-1	0	189	-181	-8	0	0	189
1983	121	0	282	-161	10	0	10	271
1984	92	0	273	-168	-12	0	0	273
1985	137	0	260	-100	-23	0	0	260
1986	272	0	402	-111	-19	0	0	402
1987	454	0	466	-5	-7	0	0	466
1988	618	0	618	107	1	107	1	509
1989	990	0	1021	252	-31	252	0	769
1990	1154	0	1312	364	-158	364	0	949
1991	1136	0	1306	438	-170	438	0	868
1992	1117	0	1289	533	-171	533	0	756
1993	1045	0	1184	654	-138	654	0	530
1994	952	0	1062	818	-110	818	0	244
1995	955	0	1021	974	-66	974	0	48
1996	899	166	1091	1091	-26	1091	0	0
1997	875	347	1226	1226	-5	1226	0	0
1998	786	347	1133	1369	23	1114	19	0
1999	688	347	1035	1507	51	1001	34	0
2000	606	347	953	1625	78	910	44	0
TOTAL	12900	1554	16239	10118	-782	9480	108	6651

-COLUMN 1 IS THE TOTAL PROJECTED SUPPLY OF GAS SURPLUS TO ALBERTA'S REQUIREMENTS FROM COLUMN 9, TABLE SD-5.

-GAS WAS ASSUMED TO FLOW EITHER EAST OR WEST TO MEET DEFICIENCIES AS REQUIRED.

-AFTER SUPPLYING BRITISH COLUMBIA AND EAST OF ALBERTA AS SHOWN IN COLUMNS 6 AND 7, THERE REMAIN QUANTITIES OF GAS WHICH PROVIDE A TEMPORARY OVERALL SURPLUS TO TOTAL DEMAND. THESE QUANTITIES, SHOWN IN COLUMN 8, ARE ASSUMED NOT TO BE PRODUCED AND ARE CONVERTED TO A FORECAST OF DELIVERABILITY SHOWN IN COLUMN 2. THEY ARE PRODUCED AT A RATE OF 1:7000 FOR EIGHT YEARS AND DECLINED THEREAFTER AT 8.22 PERCENT PER YEAR.

-THE TOTAL SURPLUS SUPPLY, COLUMN 3, IS ALLOCATED BETWEEN BRITISH COLUMBIA AND EAST OF ALBERTA BASED UPON THE PROPORTION OF THE UNSATISFIED DEMAND WHICH IS ATTRIBUTABLE TO EACH OF THESE REGIONS.

TABLE SD-9

ADJUSTMENTS TO ALBERTA UNCOMMITTED AND TREND SUPPLIES

(PETAJOULES/YEAR)

YEAR	(1) TEMPORARY SURPLUS SUPPLY	(2) DEFERRED DELIVERABILITY	UNADJUSTED (3) ALBERTA UNCOMMITTED	UNADJUSTED (4) ALBERTA TREND	ADJUSTED (5) ALBERTA UNCOMMITTED	ADJUSTED (6) ALBERTA TREND
1981	118	0	199	18	99	0
1982	189	0	279	58	149	0
1983	271	0	360	127	216	0
1984	273	0	441	229	397	0
1985	260	0	521	344	521	83
1986	402	0	574	454	574	52
1987	466	0	600	558	600	92
1988	509	0	612	658	612	148
1989	769	0	616	751	598	0
1990	949	0	609	836	497	0
1991	868	0	575	912	575	44
1992	756	0	544	976	544	220
1993	530	0	514	1028	514	498
1994	244	0	477	1070	477	826
1995	48	0	446	1101	446	1053
1996	0	166	414	1122	414	1288
1997	0	347	383	1135	383	1482
1998	0	347	350	1141	350	1488
1999	0	347	321	1140	321	1487
2000	0	347	296	1133	296	1480
TOTAL	6651	1554	9131	14788	8582	10241

-COLUMN 1 IS THE TEMPORARY SURPLUS ALBERTA SUPPLY FROM COLUMN 8, TABLE SD-8.

-COLUMN 2 IS THE DELIVERABILITY ATTRIBUTABLE TO THE QUANTITIES INDICATED TO BE SURPLUS IN COLUMN 1 AND ASSUMED NOT TO BE PRODUCED IN THE PERIOD INDICATED IN COLUMN 1.

-THE BOARD JUDGED THAT THE MAJOR ADJUSTMENTS COULD BE MADE TO THE ALBERTA RESERVES ADDITIONS FORECAST, COLUMN 4 (COLUMN 7, TABLE SD-5). ANY FURTHER ADJUSTMENTS WERE MADE TO THE BOARD'S FORECAST OF SUPPLY FROM UNCOMMITTED ALBERTA RESERVES, COLUMN 3 (COLUMNS 5 AND 6, TABLE SD-5).

-THE ADJUSTED FORECASTS OF UNCOMMITTED ALBERTA RESERVES AND SUPPLY FROM ALBERTA RESERVES ADDITIONS ARE SHOWN IN COLUMNS 5 AND 6 RESPECTIVELY.

TABLE SD-10

BRITISH COLUMBIA SUPPLY/DEMAND BALANCE

(PETAJOULES/YEAR)

	DEMAND			SUPPLY			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
YEAR	B.C. DEMAND	HUNTINGTON EXPORT	TOTAL	B.C. NET SUPPLY	ALTA SURPLUS TO B C	TOTAL (4+5)	DEFICIENCY (3-6)
1981	195	344	539	541	0	541	¯2
1982	214	344	558	566	0	566	¯8
1983	233	344	577	566	10	577	0
1984	239	344	583	595	0	595	¯12
1985	251	341	592	615	0	615	¯23
1986	257	337	594	612	0	612	¯19
1987	263	333	596	603	0	603	¯7
1988	269	330	599	597	1	599	0
1989	274	275	549	580	0	580	¯31
1990	274	0	274	432	0	432	¯158
1991	281	0	281	451	0	451	¯170
1992	290	0	290	461	0	461	¯171
1993	298	0	298	436	0	436	¯138
1994	316	0	316	427	0	427	¯110
1995	345	0	345	410	0	410	¯66
1996	359	0	359	385	0	385	¯26
1997	370	0	370	374	0	374	¯5
1998	385	0	385	362	19	381	4
1999	399	0	399	348	34	382	17
2000	412	0	412	333	44	377	35
TOTAL	5921	2992	8913	9695	108	9804	¯890

-COLUMN 1 IS TAKEN FROM COLUMN 7, TABLE SD-2.

-COLUMN 2 IS TAKEN FROM COLUMN 8, TABLE SD-2.

-COLUMN 4 IS TAKEN FROM COLUMN 8, TABLE SD-6.

-COLUMN 5 IS TAKEN FROM COLUMN 7, TABLE SD-8.

TABLE SD-11

EAST OF ALBERTA SUPPLY/DEMAND BALANCE

(PETAJOULES/YEAR)

	DEMAND			SUPPLY			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
YEAR	CANADIAN	EXPORT	TOTAL	NET SUPPLY EAST OF ALTA	ALTA SURPLUS TO EAST OF ALTA	TOTAL (4+5)	DEFICIENCY (3-6)
1981	1085	611	1696	1808	0	1808	-112
1982	1125	535	1660	1841	0	1841	-181
1983	1171	516	1687	1849	0	1849	-161
1984	1237	505	1742	1910	0	1910	-168
1985	1309	434	1743	1843	0	1843	-100
1986	1349	329	1678	1789	0	1789	-111
1987	1388	276	1664	1669	0	1669	-5
1988	1428	234	1662	1555	107	1662	0
1989	1478	222	1700	1448	252	1700	0
1990	1526	150	1676	1312	364	1676	0
1991	1548	59	1607	1169	438	1607	0
1992	1577	14	1590	1058	533	1590	0
1993	1607	14	1621	967	654	1621	0
1994	1649	14	1663	845	818	1663	0
1995	1692	11	1703	729	974	1703	0
1996	1730	0	1730	640	1091	1730	0
1997	1770	0	1770	543	1226	1769	0
1998	1822	0	1822	453	1114	1567	255
1999	1884	0	1884	377	1001	1378	506
2000	1951	0	1951	326	910	1236	716
TOTAL	30327	3923	34250	24132	9480	33612	638

-COLUMN 1 IS TAKEN FROM COLUMN 9, TABLE SD-2.

-COLUMN 2 IS TAKEN FROM COLUMN 10, TABLE SD-2.

-COLUMN 4 IS TAKEN FROM COLUMN 11, TABLE SD-7.

-COLUMN 5 IS TAKEN FROM COLUMN 6, TABLE SD-8.

TABLE SD-12

FORECAST OF REPROCESSING PLANT SHRINKAGES AND FUEL

(PETAJOULES/YEAR)

	COCHRANE				EMPRESS				EDMONTON				
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
YEAR	ETHANE	NGL	FUEL	TOTAL (1+2+3)	ETHANE	NGL	FUEL	TOTAL (5+6+7)	ETHANE	NGL	FUEL	TOTAL (9+10+11)	TOTAL (4+8+12)
1981	29	17	5	50	47	55	13	115	14	14	0	28	193
1982	29	16	5	50	47	55	8	110	23	16	0	40	200
1983	36	16	3	55	47	55	8	110	24	16	0	41	205
1984	43	15	3	61	69	68	15	152	21	15	0	37	249
1985	42	14	3	59	84	68	15	166	20	15	0	35	260
1986	41	14	3	58	84	68	15	166	22	18	0	40	265
1987	38	13	3	54	84	68	15	166	21	18	0	39	260
1988	33	11	3	47	84	68	15	166	20	18	0	38	252
1989	24	8	2	35	82	66	14	163	13	8	0	21	219
1990	23	8	2	33	81	66	14	161	12	8	0	20	213
1991	21	7	2	30	77	63	14	154	11	7	0	19	203
1992	19	7	2	28	77	62	14	152	11	7	0	18	198
1993	17	6	2	25	78	63	14	156	10	7	0	18	198
1994	15	5	1	22	81	65	14	161	10	7	0	17	200
1995	11	4	1	16	83	67	15	165	8	8	0	17	198
1996	10	3	1	14	84	68	15	166	8	8	0	17	197
1997	9	3	1	12	84	68	15	166	8	8	0	16	195
1998	8	3	1	11	76	62	13	151	8	8	0	16	178
1999	6	2	1	9	66	53	12	131	8	8	0	16	156
2000	6	2	1	8	58	47	10	116	8	8	0	16	140
TOTAL	460	174	44	677	1473	1255	266	2993	278	222	8	508	4179

-THIS TABLE REPRESENTS THE BOARD'S FORECASTS OF REPROCESSING PLANT SHRINKAGES AND FUEL BASED ON THE THROUGHPUTS PROJECTED IN THIS SUPPLY-DEMAND BALANCE.

-THE BOARD'S FORECAST OF SHRINKAGE AND FUEL AT COCHRANE BASED ON PROJECTED THROUGHPUT IS SHOWN IN COLUMNS 1, 2 AND3.

-THE BOARD'S FORECAST OF SHRINKAGE AND FUEL AT EMPRESS BASED ON PROJECTED THROUGHPUT IS SHOWN IN COLUMNS 5, 6 AND 7.

-THE FORECAST OF SHRINKAGE AND FUEL AT EDMONTON BASED ON DOME'S SUBMISSION IS SHOWN IN COLUMNS 9, 10 AND 11.

TABLE SD-13

TOTAL CANADIAN SUPPLY/DEMAND BALANCE

(PETAJOULES/YEAR)

	DEMAND			SUPPLY						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
YEAR	DOMESTIC	EXPORT	TOTAL	TOTAL CONTROLLED	ALBERTA UNCOMMITTED	B C UNCOMMITTED	ALTA DEFERRED	TREND SUPPLY	TOTAL (4+5+6+7+8)	DEFICIENCY (3-9)
REMAINING RESERVES AT 31 DECEMBER 1980				59201	13441	530	3066	37470	113708	
1981	2076	1675	3751	3646	99	0	3	3	3751	0
1982	2157	1863	4020	3859	149	0	3	9	4020	0
1983	2304	1845	4150	3911	216	0	3	20	4150	0
1984	2455	1843	4298	3857	397	4	4	36	4298	0
1985	2573	1743	4316	3643	521	8	6	138	4316	0
1986	2638	1550	4188	3471	574	12	6	124	4188	0
1987	2699	1317	4017	3211	600	17	6	182	4017	0
1988	2774	1100	3874	2973	612	21	12	257	3874	0
1989	2855	642	3498	2723	598	24	27	126	3498	0
1990	2874	244	3118	2412	497	25	42	142	3118	0
1991	2897	145	3043	2203	575	26	39	200	3043	0
1992	2943	62	3005	2010	544	26	35	390	3005	0
1993	2989	54	3043	1791	514	26	32	680	3043	0
1994	3062	14	3075	1528	477	25	28	1017	3075	0
1995	3143	11	3155	1386	446	25	46	1252	3155	0
1996	3214	0	3214	1238	414	23	45	1493	3214	0
1997	3281	0	3281	1086	383	22	100	1691	3281	0
1998	3374	0	3374	948	350	20	97	1699	3114	259
1999	3475	0	3475	820	321	19	95	1698	2952	523
2000	3585	0	3585	719	296	17	112	1690	2834	750
TOTAL	57368	14109	71477	47437	8582	339	740	12847	69945	1533

-FIGURES MAY NOT ADD DUE TO ROUNDING.

-BOARD ESTIMATES OF THE REMAINING MARKETABLE RESERVES AT 31 DECEMBER, 1980 WHICH SUPPORT THE NEB FORECASTS OF SUPPLY ARE SHOWN AT THE TOP OF COLUMNS 4 TO 9.

-COLUMN 5 INCLUDES THE UNCOMMITTED ALBERTA RESERVES AT 31 DECEMBER, 1979, THE TOTAL RESERVES BEYOND ECONOMIC REACH IN ALBERTA AND THE 1980 ALBERTA RESERVES ADDITION.

-COLUMN 6 IS THE SUPPLY FORECAST FROM THE 1980 RESERVES ADDITION IN BRITISH COLUMBIA.

-COLUMNS 1 TO 8 INCLUSIVE ARE TAKEN FROM COLUMNS 11, 12 AND 13, TABLE SD-2; COLUMN 14, TABLE SD-4; COLUMN 5, TABLE SD-9; COLUMN 6, TABLE SD-6; COLUMN 4, TABLE SD-5; AND COLUMN 6, TABLE SD-9.

-THE TOTAL DEFICIENCY IN COLUMN 10 INCLUDES THE POSITIVE DEFICIENCIES FOR BRITISH COLUMBIA AND EAST OF ALBERTA FROM COLUMN 7, TABLE SD-10 AND COLUMN 7, TABLE SD-11 RESPECTIVELY.

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